FACT SHEET
Powertech (USA) Inc.
Dewey-Burdock Class V Deep Injection Wells
Custer and Fall River Counties, South Dakota
EPA PERMIT NO. SD52173-00000

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1.0 INTRODUCTION

This FACT SHEET fulfills the requirements found at 40 CFR § 124.8 by setting forth the principal facts and the significant factual, legal, methodological and policy questions considered in preparing this Underground Injection Control (UIC) Class V Permit.

UIC Permits specify the conditions and requirements for construction, operation, monitoring and reporting, and plugging of injection wells to prevent the movement of fluids into underground sources of drinking water (USDWs). Under Title 40 Code of Federal Regulations (CFR) 144 subpart D, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General Permit conditions, for which content is mandatory and not subject to site-specific differences (40 CFR parts 144, 146 and 147), are not discussed in this document. UIC regulations specific to injection wells in South Dakota are found at 40 CFR 147 subpart QQ.

This UIC Class V Permit is proposed as an Area Permit, which means that it authorizes more than one injection well. The EPA has evaluated the cumulative effects of the construction and operation of all Class V injection wells authorized under this Area Permit according to 40 CFR § 144.33(c)(3) as discussed under the document entitled *Cumulative Effects Analysis of the Dewey-Burdock UIC Area Permits*. Upon the Effective Date, this Area Permit will authorize the construction of a new injection well project governed by the conditions specified herein. Under 40 CFR § 144.36, the Area Permit will be in effect for a period of ten years from the Permit Effective Date unless terminated for reasonable cause under 40 CFR § 144.40.

The Area Permit requires Powertech to submit the information specified in the Class V Area Permit Part II to the EPA for review to obtain written authorization to inject from the EPA before any injection into wells covered by the Area Permit may operate.

1.1 The Public Review Process

The EPA Region 8 UIC Program published a public notice on the EPA Region 8 UIC website: https://www.epa.gov/uic/dewey-burdock-class-iii-and-class-v-injection-well-applications announcing the proposal of two UIC Area Permits to Powertech (USA) Inc. for injection activities related to uranium recovery and an accompanying aquifer exemption. One is a UIC Class III Area Permit for injection wells related to the In-Situ Recovery (ISR) of uranium; the second is a UIC Class V Area Permit for deep injection wells that will be used to dispose of ISR process waste fluids into the Minnelusa Formation after treatment to meet radioactive waste and hazardous waste standards. The proposed aquifer exemption is associated with the Class III permit. The public notice was published on March 6, 2017 and the public comment period will end on May 19, 2017. The public notice states that the EPA is soliciting comments on the two UIC Area Permits and the aquifer exemption record of decision (ROD). Any interested person may submit written comments on these two draft permits or the aquifer exemption ROD by emailing them to Valois Shea at shea.valois@epa.gov or mailing them to Valois Shea at the address at the beginning of this Fact Sheet. To be included in the Administrative Record, written comments must be received by midnight Mountain Time on May 19, 2017.

A notice of the issuance of the draft UIC permits was also published in the *Lakota Country Times,* the *Edgemont Herald Tribune,* the *Rapid City Journal,* and the *Custer County Chronicle*. A notice was also posted on http://www.indianz.com. All of these notices directed readers to the EPA Region 8 UIC Program website which contains links to the Administrative Record for these proposed actions.

The EPA has scheduled the following public hearings:
Thursday, April 27, 2017 from 4:00 to 8:30 p.m. (with a break from 6:00 to 6:30 p.m.)
Niobrara Lodge
803 US Highway 20
Valentine, Nebraska 69201

Monday-Tuesday, May 8-9, 2017, from 1:00 to 8:00 p.m. (with a break from 5:00 to 6:00 p.m.)
The Best Western Ramkota Hotel
2111 N. LaCrosse Street
Rapid City, South Dakota 57701

Wednesday, May 10, 2017, from 1:00 to 8:00 p.m. (with a break from 5:00 to 6:00 p.m.)
The Mueller Center
801 S 6th Street
Hot Springs, South Dakota 57747

Thursday, May 11, 2017, from 1:00 to 8:00 p.m. (with a break from 5:00 to 6:00 p.m.)
St. James Catholic Church
310 3rd Avenue
Edgemont, South Dakota 57735

At the public hearings, any person may submit oral or written statements and data concerning the draft permits. Reasonable limits may be set upon the time allowed for oral statements, and the submission of statements in writing is required for the public record. As stated under 40 CFR § 124.13, "[a]ll persons, including applicants, who believe any condition of a draft permit is inappropriate or that the [EPA's] tentative decision to...prepare a draft permit is inappropriate, must raise all reasonably ascertainable issues and submit all reasonably available arguments supporting their position by the close of the public comment period (including the public hearing)... Any supporting materials which are submitted shall be included in full and may not be incorporated by reference, unless they are already part of the [Draft Area Permit] Administrative Record...or consist of State or Federal statutes and regulations, [are] EPA documents of general applicability, or [are] other generally available reference materials. Commenters shall make supporting materials not already included in the [list above] available to [the] EPA" by presenting a printed copy at a public hearing, emailing the information to Valois Shea, or providing a website where the information may be viewed. The EPA will provide a written transcript of the hearing to the public as part of the Administrative Record for the Final Area Permit decisions.

At the close of the public comment period, the EPA will review all comments received during the public comment period and during the public hearings and prepare a written statement addressing all the comments received that are relevant to the UIC Class V Draft Area Permit. The EPA will issue a final permit decision and notify the applicant and each person who has submitted written comments or requested notice of a final permit decision. A final permit decision means a final decision to issue or deny the permit. The written statement addressing all relevant comments received will be included in the notification of the final permit decision. The notice will also include reference to the procedures for appealing a decision on a UIC permit under 40 CFR § 124.19.

If the EPA receives comments on the Draft Area Permit from the public during the public review process, the Final Area Permit decision will not be effective until 30 days after the Final Permit issue date as required by 40 CFR § 125.15. The purpose of this 30-day period is to allow time for those who submitted comments or participated in a public hearing to appeal the final permit decision as described under 40 CFR § 124.19 which is paraphrased below.

Within 30 days after the UIC final permit decision has been issued, any person who filed comments on that draft permit or participated in a public hearing may petition the Environmental Appeals Board to review any condition of the permit decision. Any person who failed to file comments or failed to participate in a public hearing on the draft permit may petition for administrative review only to the extent of the changes from the draft to the final permit decision. The 30-day period within which a person may request review under this section begins with the service of notice of the EPA's final permit decision unless a later date is specified in that notice. The petition shall include a statement of the reasons supporting that review, including a demonstration that any issues being raised were raised during the public comment period (including any public hearing) to the extent required by these regulations and when appropriate, a showing that the condition in question is based on:

(1) A finding of fact or conclusion of law which is clearly erroneous, or
(2) An exercise of discretion or an important policy consideration which the Environmental Appeals Board should, in its discretion, review.

Within a reasonable time following the filing of the petition for review, the Environmental Appeals Board will issue an order granting or denying the petition for review. To the extent review is denied, the conditions of the final permit decision become final agency action.

1.2 Contact Information

For any additional information about the two Draft Area Permits, the aquifer exemption ROD or the public review process, please contact Valois Shea at the phone number or email address shown at the beginning of this Fact Sheet.

2.0. GENERAL INFORMATION AND DESC RIPTION OF FACILITY

Powertech (USA) Inc.
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Greenwood Village, Colorado 80111

submitted an application for a UIC Program Class V Area Permit proposing to construct and operate up to eight (8) deep injection wells within the Dewey-Burdock Project Boundary to be used for the disposal of treated uranium ISR process wastewater into the Minnelusa and Deadwood Formations. At the time the Class V Area Permit Application was submitted, Powertech anticipated that the two (2) Minnelusa and the two (2) Deadwood injection wells proposed in the Class V Permit Application would provide adequate disposal capacity for the volume of uranium ISR process wastewater that is expected to be generated at the site. As further explained below in Section 2.3, Powertech did not intend to request additional injection wells to be added under the Class V Area Permit unless the first four (4) wells did not provide adequate disposal capacity. However, Powertech withdrew the permitting request for the two Deadwood injections wells in a letter dated December 9, 2016.

This Class V Area Permit authorizes up to four (4) wells for injection into the Minnelusa Formation only. Powertech originally proposed the construction of the two (2) Minnelusa Formation injection wells listed in Table 1, but may elect to construct up to two (2) additional injection wells allowed under this Class V Area Permit. If Powertech decides that more than four (4) injection wells are needed to provide enough capacity to disposed of the treated ISR waste fluids, a modification under this permit will be required per 40 CFR § 144.39 and 40 CFR § 124.5. This process will involve issuing a draft permit modification subject to public comment on the modifications only.

Table 1. Injection Wells Proposed under the Class V Area Permit

Well Permit Number	Well Name	Proposed Injection Zone	Anticipated Injection Zone Depth[1] (feet below ground surface)	Location within Project Area
SD52173-08764	DW No. 1	Minnelusa Formation	~1,615 - ~2,205	Burdock
SD52173-08765	DW No. 3	Minnelusa Formation	~1,950 - ~2,540	Dewey

~ = approximately

[1] The approximate depths shown in this table are extrapolated from the type logs described in the Class V Permit Application. Actual injection zone depths will be determined from drillhole logs during well construction.

The Class V Permit Application, including the required information and data necessary to issue a UIC permit in accordance with 40 CFR parts 124, 144, 146 and 147, was reviewed by the EPA and determined to be complete.

This Class V Area Permit is issued for a time period of ten (10) years after the Permit Effective Date and will expire after that time. The Class V Area Permit also may be terminated upon delegation of primary enforcement responsibility for the Class V UIC Program to the State of South Dakota unless the State agency chooses to adopt and enforce this Permit. If Powertech wishes to continue any activity regulated by this Permit after the expiration date of this Class V Area Permit, Powertech must submit a complete application for anew Permit at least 180 days before the Class V Area Permit expires.

2.1 Injection Well Classification

The injection wells authorized under this permit are classified as Class V industrial wastewater injection wells. The proposed injection zone for injection wells DW No. 1 and DW No. 3 is the Minnelusa Formation, which overlies the Madison Formation, a USDW. Typically, Class I radioactive waste injection wells are used for process wastewater disposal at uranium ISR sites because process wastewater at these types of facilities usually meets the definition of "radioactive waste" under 40 CFR § 144.3. Class I radioactive waste disposal wells are required to inject fluids below the lowermost formation containing an underground source of drinking water within one quarter mile of the well bore per40 CFR § 144.6(a)(3). Radioactive waste disposal above USDWs are classified as Class IV wells and are banned per 40 CFR § 144.13. Because the proposed Minnelusa injection zone for DW No. 1 and DW No. 3 is located above a USDW, these wells do not fit the regulatory definition of a Class I injection well. Therefore, in order to be able to inject in the Minnelusa, above USDWs, the permit requires Powertech to treat the injectate so that it does not fall under the definition of "radioactive waste." According to 40 CFR § 144.5(e)

Class V injection wells are those not included in Class I, II, III, IV or VI. Therefore, DW No. 1 and DW No. 3 must be classified as Class V injection wells.

Because these two wells will be used as deep disposal wells, the Class V Area Permit contains the protective construction and monitoring requirements designed for Class I injection wells. However, because these wells are Class V wells, the Class V Area Permit contains permit limits requiring injectate constituent concentrations to be at or below radioactive waste standards set in 10 CFR Part 20, Appendix B, Table II, Column 2 and hazardous waste standards set in 40 CFR § 261.24 Table 1.

The proposed injection zone for injection wells DW No. 2 and DW No. 4 is the Deadwood Formation, which is expected to lie beneath all USDWs in the area. These two wells fit the regulatory definition of Class I wells found at 40 CFR § 144.6(a). Even if Powertech treats the injectate for these two wells so that injectate constituent concentrations would be at or below radioactive waste standards set in 10 CFR Part 20, Appendix B, Table II, Column 2 and hazardous waste standards set in 40 CFR § 261.24 Table 1, these wells would still meet the definition of Class I other industrial well found at 40 CFR § 144.6(a)(2). South Dakota regulation 74:55:02:02 prohibits Class I injection wells in the State. When the EPA informed Powertech that the DW No. 2 and DW No. 4 wells proposed for injection into Deadwood Formation are classified as Class I wells under UIC regulation 40 CFR § 144.6(a)(2), Powertech submitted a letter to the EPA withdrawing the request for authorization for construction and operation of wells injecting into the Deadwood Formation. Because there is no longer an active application for injection into the Deadwood Formation, there is no agency action related to injection into this formation.

2.2 Project Description

The proposed Dewey-Burdock uranium ISR site is located in the southern Black Hills region in South Dakota on the South Dakota-Wyoming state line in southwest Custer and northwest Fall River Counties as shown in Figure 1. The site is located approximately 13 miles northwest of Edgemont, SD and 46 miles west of the western border of the Pine Ridge Reservation. The Class V Project Site is divided into two areas: the Dewey Area, comprising the western portion of the Project Site and the Burdock Area, comprising the eastern portion of the Project Site, as shown in Figure 2.

Powertech proposes recovering uranium from ore deposits in the Fall River Formation and Lakota Formation Chilson Sandstone of the Inyan Kara Group using the ISR process. The sub-units of the Inyan Kara Group are shown in the stratigraphic column in Figure 3, which shows the geologic formations present at the Dewey-Burdock Project Site.

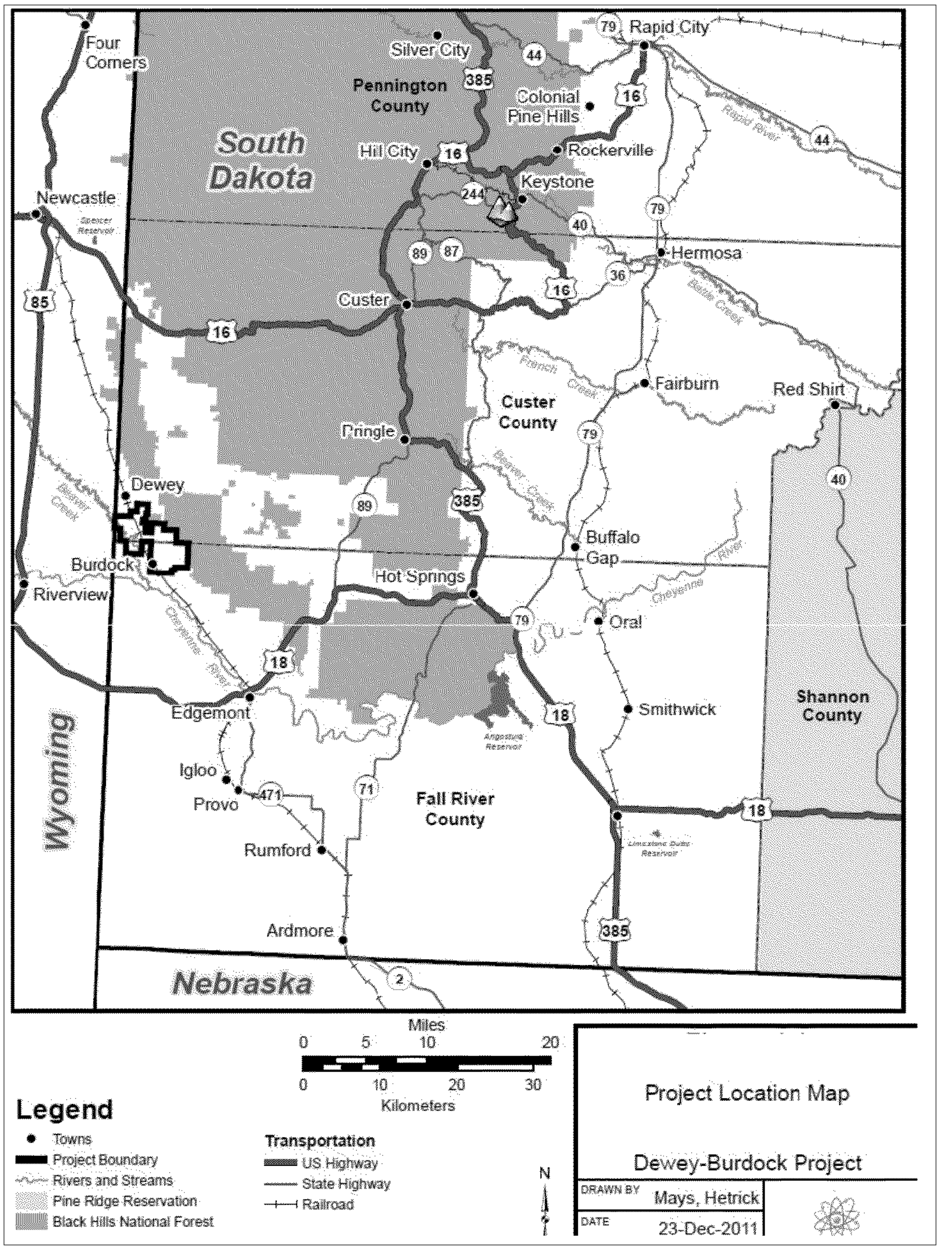

Figure 1. Dewey-Burdock Project Location

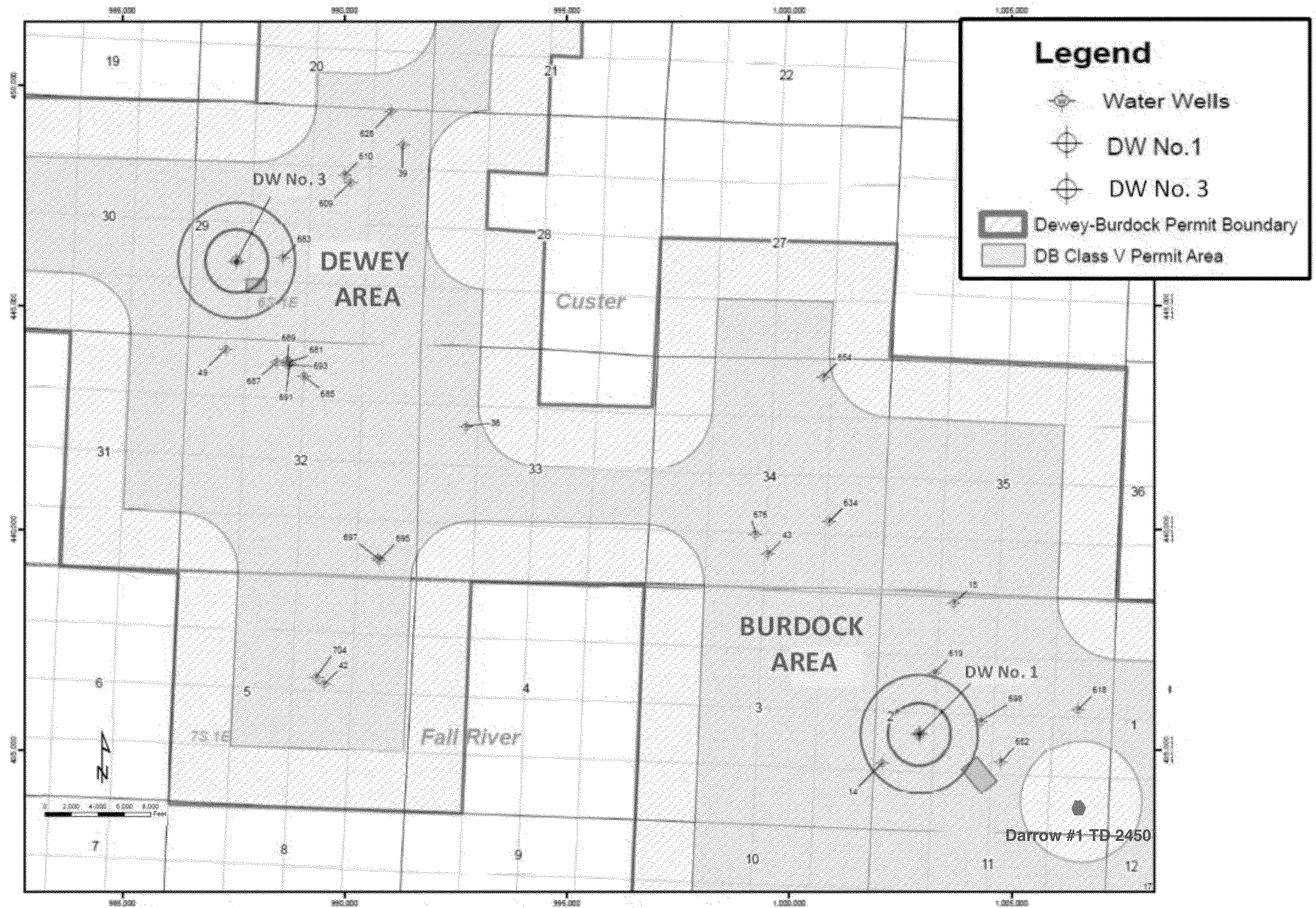

Figure 2. Approximate Dewey-Burdock Class V Permit Area

ARC 43-11 Peterson TD 2250'

PRC 21-14 Peterson TD 2284 PBTD 850

ERATHEM	SYSTEM	ABBREVIATION FOR STRATIGRAPHIC INTERVAL	STRATIGRAPHIC UNIT	THICKNESS IN FEET	DESCRIPTION
CENOZOIC	QUATERNARY & TERTIARY (?)	QTac	UNDIFFERENTIATED SANDS AND GRAVELS	0-50	Aluvial and colluvial materials.
		Tw	WHITE RIVER GROUP	0-300	Light colored clays with sandstone channel fillings and local limestone lenses.
	TERTIARY	Tui	INTRUSIVE IGNEOUS ROCKS	--	Includes rhyolite, latite, trachyte, and phonolite.
MESOZOIC	CRETACEOUS	Kps	PIERRE SHALE	1,200-2,700	Principal horizon of limestone lenses giving teepee buttes. Dark-gray shale containing scattered concretions. Widely scattered limestone masses, giving small teepee buttes. Black fissile shale with concretions.
			NIOBRARA FORMATION	[1]80-300	Impure chalk and calcareous shale.
			CARLILE SHALE: Turner Sandy Member; Wall Creek Member	[1]350-750	Light-gray shale with numerous large concretions and sandy layers. Dark-gray shale.
			GREENHORN FORMATON	225-380	Impure slabby limestone. Weathers buff. Dark-gray calcareous shale, with thin Orman Lake limestone at base.
			GRANEROS GROUP: BELLE FOURCHE SHALE	150-850	Gray shale with scattered limestone concretions. Clay spur bentonite at base.
			GRANEROS GROUP: MOWRY SHALE	125-230	Light-gray siliceous shale. Fish scales and thin layers of bentonite.
			GRANEROS GROUP: MUDDY SANDSTONE / NEWCASTLE SANDSTONE	0-150	Brown to light-yellow and white sandstone.
			GRANEROS GROUP: SKULL CREEK SHALE	150-270	Dark-gray to black siliceous shale.
		Kk	INYAN KARA GROUP: FALL RIVER FORMATION	10-200	Massive to slabby sandstone.
			INYAN KARA GROUP: LAKOTA FM: Fuson Shale; Minnewaste Limestone; Chilson Member	10-190; 0-25; 25-485	Coarse gray to buff cross-bedded conglomeratic sandstone, interbedded with buff, red, and gray clay, especially toward top. Local fine-grained limestone.
	JURASSIC	Ju	MORRISON FORMATION	0-220	Green to maroon shale. Thin sandstone.
			UNKPAPA SS	0-225	Massive fine-grained sandstone.
			SUNDANCE FORMATION: Redwater Member; Lak Member; Hulett Member; Stockade Beaver Mem.; Canyon Spr Member	250-450	Greenish-gray shale, thin limestone lenses. Glauconitic sandstone; red sandstone near middle.
			GYPSUM SPRING FORMATION	0-45	Red siltstone, gypsum, and limestone.
	TRIASSIC	TRPs	SPEARFISH FORMATION; Goose Egg Equivalent	375-800	Red sandy shale, soft red sandstone and siltstone with gypsum and thin limestone layers. Gypsum locally near the base.
PALEOZOIC	PERMIAN	Pmk	MINNEKAHTA LIMESTONE	[1]25-65	Thin to medium-bedded fine-grained, purplish-gray laminated limestone.
		Po	OPECHE SHALE	[1]25-150	Red shale and sandstone.
	PENNSYLVANIAN	PIPm	MINNELUSA FORMATION	[1]375-1,175	Yellow to red cross-bedded sandstone, limestone, and anhydrite locally at top. Interbedded sandstone, limestone, dolomite, shale, and anhydrite. Red shale with interbedded limestone and sandstone at base.
	MISSISSIPPIAN	MDm	MADISON (PAHASAPA) LIMESTONE	[1]250-1,000	Massive light-colored limestone. Dolomite in part. Cavernous in upper part.
	DEVONIAN		ENGLEWOOD FORMATON	30-60	Pink to buff limestone. Shale locally at base.
	ORDOVICIAN	Ou	WHITEWOOD (RED RIVER) FORMATION	[1]0-235	Buff dolomite and limestone.
			WINNIPEG FORMATION	[1]0-150	Green shale with siltstone.
	CAMBRIAN	O€d	DEADWOOD FORMATION	[1]0-500	Massive to thin-bedded buff to purple sandstone. Greenish glauconitic shale, flaggy dolomite, and flat-pebble limestone conglomerate. Sandstone, with conglomerate locally at the base.
PRECAMBRIAN		p€u	UNDIFFERENTIATED METAMORPHIC AND IGNEOUS ROCKS		Schist, slate, quartzite, and arkosic grit. Intruded by diorite, metamorphosed to amphibolite, and by granite and pegmatite.

[1]Modified based on drill-hole data

Modified from information furnished by the Department of Geology and Geological Engineering, South Dakota School of Mines and Technology (written commun., January 1994)

Figure 3. Stratigraphic Column from Naus et al., 2001, Showing the Geologic Formations Present at the Dewey-Burdock Project Site

Note: The Gypsum Springs Formation is identified in only one of the oil and gas test well logs near the Dewey-Burdock site. The other logs include it with the Spearfish Formation because of similar lithology (rock type). The Gypsum Springs is not included as a separate formation in Table 3.

The ISR process involves using Class III[2] injection wells to introduce a lixiviant into subsurface uranium ore deposits to leach the uranium from the ore deposit. Powertech proposes using a lixiviant consisting of groundwater from the uranium-bearing aquifer, adding gaseous oxygen to mobilize uranium into solution and gaseous carbon dioxide to hold the uranium in solution while it is transported to the production wells.

The uranium-bearing lixiviant will be pumped from the production wells to a processing plant, where the dissolved uranium will be removed from solution using an ion-exchange resin. After uranium removal, the groundwater will be re-fortified with oxygen and carbon dioxide, recirculated and reinjected back into the well field via injection wells. Once the ion-exchange resin is loaded with uranium, the loaded resin will be stripped using a saltwater solution. The resulting barren resin then will be used again to recover more uranium. The uranium-bearing saltwater solution will be pumped through a precipitation process, where the uranium will be precipitated as a yellow, solid uranium oxide (yellowcake or U_3O_8). The precipitated uranium oxide then will be filtered, washed, dried and packaged in sealed containers for shipment to a processing site where it will be further processed until it can be used in the uranium fuel cycle. After treatment to meet radioactive waste and hazardous waste thresholds, the waste fluids from this process will be injected into the proposed Class V deep disposal wells. Additional waste fluids will be generated by "bleed" from the ISR well fields that is generated as a larger volume of lixiviant is pumped from a wellfield than in reinjected into the wellfield through the Class III in jection wells in order to maintain the inward hydraulic gradient as discussed in Section 9.2 of the Class III Area Permit Fact Sheet.

After the uranium recovery process has been completed in a well field, the groundwater restoration process begins for that well field. The contaminated groundwater is pumped from the well field and treated using Reverse Osmosis (RO). The restoration process also produces "bleed" fluids. The restoration "bleed" and the reject water from the RO treatment are part of the approved injectate for the proposed UIC deep disposal wells as described under Section 7.8 of this document.

2.3 Well Locations

The Class V Area Permit authorizes the construction and operation of up to four (4) deep Class V disposal wells injecting into the Minnelusa Formation within the Class V Area Permit Boundary described above. At this time, Powertech has proposed the construction of only twoMinnelusa injection wells. The proposed locations for these two wells are shown in Table 2 and Figures 4a and 4b. Powertech intends to construct the additional wells only if additional disposal capacity is needed to dispose of the full volume of ISR waste fluids produced.

Table 2. Approximate Locations of Injection Wells Proposed under the Class V Area Permit

Well Permit Number	Well Name	Latitude	Longitude	Section/Township/Range	County
SD52173-08764	DW No. 1	43.469772181	-103.971938654	NENWSW Sec 2 T7S R1E	Fall River
SD52173-08766	DW No. 3	43.4971737527	-104.031570321	SENWSW Sec 29 T6S R1E	Custer

[2]Class III uranium ISR injection wells are used for the injection of a mineral recovery solution called lixiviant. For information about the Class III wells and Class III Area Permit, refer to the Fact Sheet for the UIC Class III injection well draft area permit SD31231-00000.

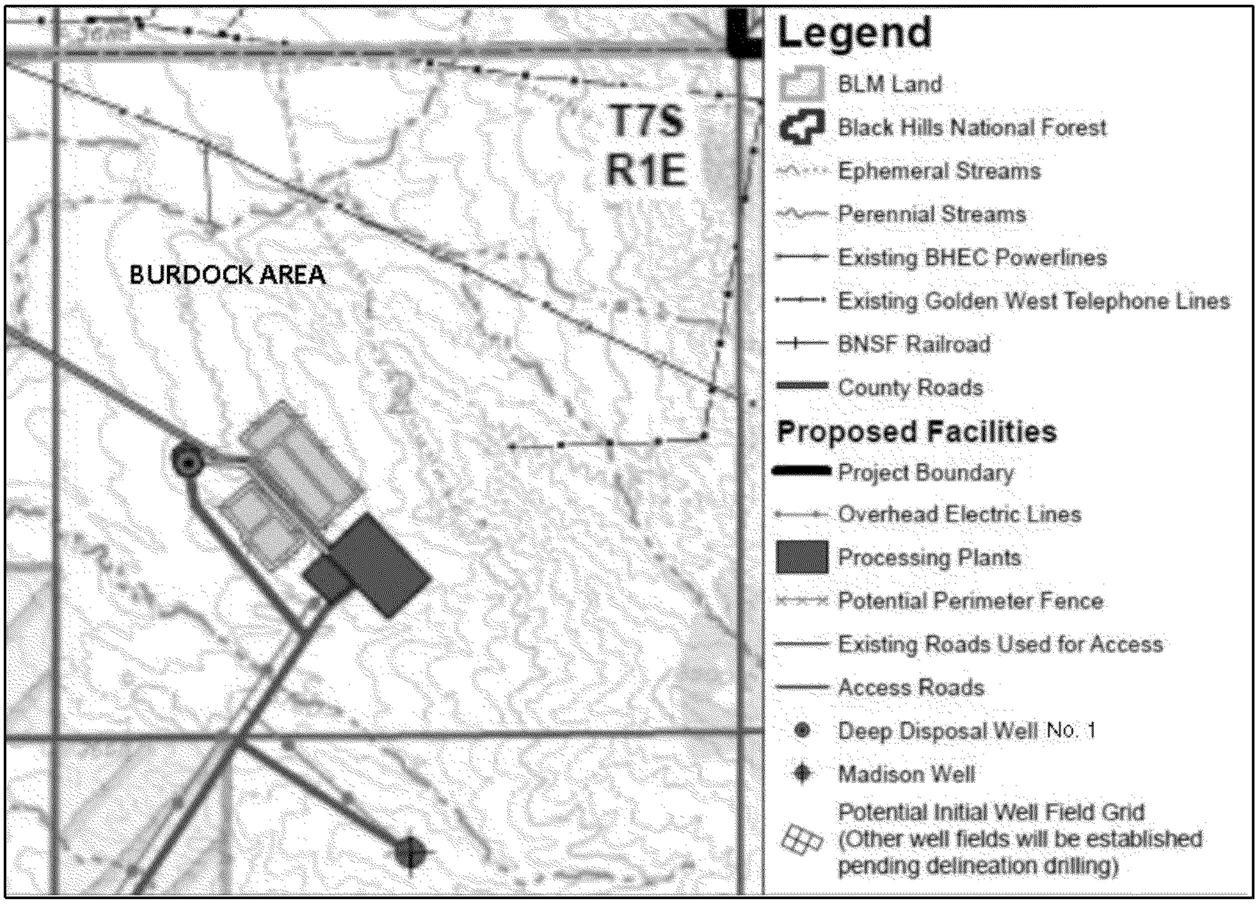

Figure 4a. Approximate Location of the Deep Class V Disposal Well in the Burdock Area

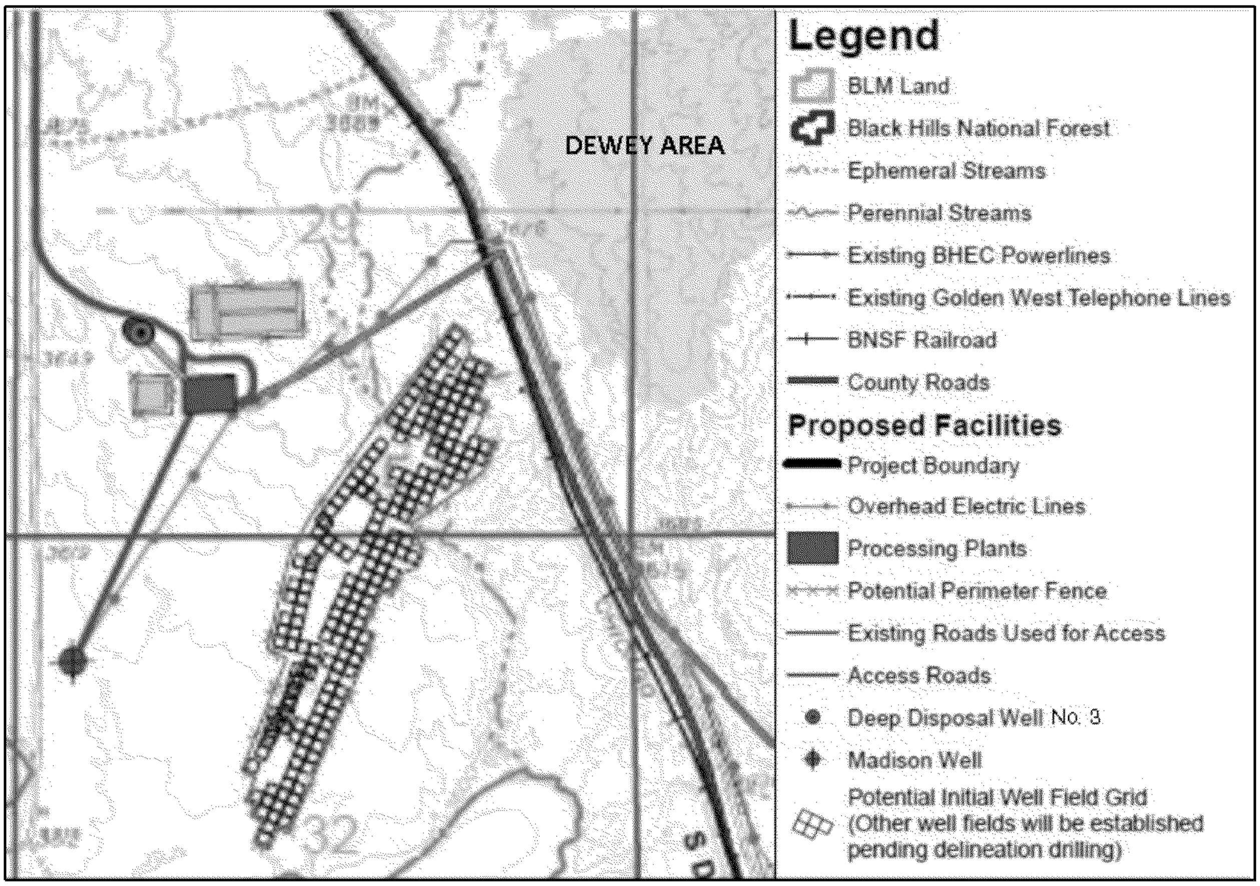

Figure 4b. Approximate Location of the Deep Class V Disposal Well in the Dewey Area

If these two wells do not provide enough disposal capacity, Powertech may propose the construction of up to two additional Class V wells injecting into the Minnelusa injection zone. The EPA will authorize additional Minnelusa injection zone wells only if the additional wells can meet the requirements in the Class V Area Permit.

3.0 HYDROGEOLOGIC SETTING

3.1 Geologic Setting

The geologic formations present at the Dewey-Burdock site are listed in Table 3.

Table 3. Geologic Setting

Formation Name	Burdock Area		Dewey Area		Lithology
	Top[3] (feet)	Base (feet)	Top (feet)	Base (feet)	
Graneros Group	0	190	0	525	
Belle Fourche Shale					Gray shale with scattered limestone concretions and basal clay bentonite.
Mowry Shale					Light-gray shale with thin layers of bentonite
Skull Creek Shale					Dark-gray shale
Inyan Kara Group					
Fall River Formation ISL target	190	315	525	650	Interbedded fluvial sandstones and shale
Lakota Formation	315	425	650	760	Interbedded fluvial sandstones and shale
Fuson Shale	315	355	650	690	Shale
Chilson Sandstone ISL target	355	425	690	760	Interbedded fluvial sandstones and shale
Morrison Formation	425	560	760	895	Variegated shales
Unkpapa Sandstone	560	640	895	975	Sandstone
Sundance Formation	640	920	975	1255	Shale, sandstone, thin beds of limestone Basal sandstone
Spearfish Formation	920	1240	1255	1575	Red shales and siltstones with white gypsum beds and limestone layers.
Goose Egg Formation	1240	1480	1575	1815	Forells Lime Member (limestone) Glendo Shale Member(shale)
Minnekahta Limestone	1480	1520	1815	1855	Thin to medium-bedded fine-grained, purplish-gray laminated limestone
Opeche Shale	1520	1615	1855	1950	Red sandy shale, soft red sandstone and siltstone with gypsum and thin limestone layers. Gypsum locally near the base.
Minnelusa Formation					
Minnelusa Porosity Injection Zone	1615	2205	1950	2540	Porous eolian sandstones with interbedded shale and anhydrite (porosity zone)
Minnelusa Lower Confining Zone	2205	2765	2540	3100	Interbedded cemented sandstones with dolomite, shale and anhydrite[4]
Madison Formation	2765	3060	3100	3395	Limestone and dolomite Madison Aquifer occurs within the top 100 to 200 feet of the formation.[4]
Englewood Formation	3060	3095	3395	3430	Pink to buff limestone. Shale locally at base.
Deadwood Formation	3095	3195	3430	3530	Sandstone with beds of shale and limestone ; basal conglomerate
Granite wash					Granitic pebbles formed by weathering of Precambrian basement locally present between the Deadwood Formation and the Precambrian basement
Precambrian basement	3195		3530		Undifferentiated metamorphic and igneous rocks

[3] Formation tops are based extrapolations from exploratory drillhole logs and oil and gas well logs discussed in the Class V Permit Application.

[4] Greene, 1993. Hydraulic properties of the Madison aquifer system in the western Rapid City area, South Dakota.

3.2 Proposed Injection Zone

An injection zone is a geological formation, group of formations, or part of a formation that receives fluids through an injection well. The proposed injection zone is a portion of the Minnelusa Formation listed in Table 4.

Injection will only be authorized into an injection zone that is separated from USDWs by confining zones which do not allow detectable vertical fluid movement out of the injection zone within the Area of Review (AOR) (see Section 4.0 below).

Table 4. Proposed Injection Zone

Formation Name	Depth Top (feet)	Depth Base (feet)	TDS (mg/L)
Minnelusa Porosity Zone (Burdock)	1,615	2,205 – 2,450	16,652 - 21,391
Minnelusa Porosity Zone (Dewey)	1,950	2,540 – 2,785	16,652 - 21,391

The Minnelusa injection zone includes the "porosity zone" occurring in the Upper Minnelusa Formation where the sandstones are more permeable due to lack of mineral precipitation between the sand grains filling up pore space. Based on analysis of logs from the oil and gas test wells within the Dewey-Burdock AOR, the porosity zone appears to occur as deep as the 2nd Leo sand. The Lower Minnelusa Formation sandstones are less permeable due to greater prevalence of cement filling the pore spaces between sand grains. The Lower Minnelusa Formation also contains more dolomite and shale beds. Information on the porosity of the Minnelusa Formation is available from numerous oil and gas exploration wells near the Dewey-Burdock Project Area. The lithologic description of the Minnelusa Formation included in Appendix A of this Fact Sheet is from the Earl Darrow #1 (API# 40 047 05095) exploratory oil and gas well. The porosity of the sandstones is noted in this log. The Class V Permit Application indicates that Powertech expects the base of the Minnelusa porosity injection zone to be located at a depth of approximately 2,205 feet below ground surface in the Burdock Area and approximately 2,540 feet below ground surface in the Dewey Area. The lithologic logs from the Darrow #1 indicates that there is fair porosity in a sandstone as deep as 2,450 feet below ground surface, which appears to be in the 3rd Leo sand. The Class V Area Permit allows Powertech to drill deeper in order to evaluate deeper sandstone units within the Minnelusa Formation to determine if there are any sandstone units with adequate porosity and permeability to include as part of the injection zone.

The Minnelusa injection zone is not expected to be a USDW. The definition of a USDW is found at 40 CFR § 144.3: *Underground source of drinking water (USDW)* means an aquifer or its portion:

(a)(1) Which supplies any public water system; or

(2) Which contains a sufficient quantity of ground water to supply a public water system; and

(i) Currently supplies drinking water for human consumption; or

(ii) Contains fewer than 10,000 mg/L total dissolved solids (TDS); and

(b) Which is not an exempted aquifer.

Fluid samples have been collected from the Minnelusa Formation in a number of locations near the Dewey-Burdock Project Area. Table D-2 in the Class V Permit Application shows the TDS analytical results. The fluid samples collected nearest the Dewey-Burdock site were from the Sun #1 Lance Nelson (API# 40 047 05089) oil and gas test well. The Sun #1 Lance Nelson is located at NESE Section 21, Township 7 South, Range 1 East, 2,400 feet to the southwest of the proposed location for DW No. 1. Minnelusa aquifer samples from the Sun #1 Lance Nelson show TDS values ranging from 16,652 to 21,391 mg/L. Based on this information and the fact that the Minnelusa porosity zone contains the soluble mineral anhydrite, the Minnelusa aquifer is not expected to be a USDW. To verify the TDS values in the Minnelusa injection zone, formation fluid samples will be collected during the drilling of the injection wells.

Part II, Sections D.2.b and D.2.c and Part V, Sections D.1.b and D.1.c of the Class V Area Permit contain the requirements for aquifer fluid sample collection procedures to ensure that fluid samples collected from each aquifer, including the injection zone, are representative of the aquifer fluids. Powertech must collect fluid samples from the Minnelusa Formation during the drilling of Class V injection wells DW No. 1 and DW No. 3. The Area Permit requires that a minimum of five (5) samples must be collected from the injection zone at each well site and analyzed for TDS to verify that the Minnelusa aquifer fluids are above 10,000 mg/L TDS and confirm that the Minnelusa aquifer is not a USDW.

If results from the analysis of TDS show that the injection zone is a USDW and Powertech still wants to use the Minnelusa as an injection zone, a major modification of the Area Permit would be required. A major permit modification per 40 CFR § 144.39 and 40 CFR § 124.5 involves issuing a draft permit modification subject to public comment on the modifications only.

3.3 Confining Zones

A confining zone is a geological formation, part of a formation, or a group of formations that limits fluid movement above and below the injection zone. The confining zones for the Minnelusa injection zone are listed in Table 5. The EPA has evaluated the information included in the Class V Permit Application related to the confining zones, has reviewed references on the hydrogeology of the Black Hills area and has evaluated the overlying and underlying confining zones logged in oil and gas test wells around the Dewey-Burdock Project Area. Based on available information sources, the EPA has determined that there is ample evidence that the confining zones at the Dewey-Burdock Project Site are competent and will contain the injectate within the proposed injection zone. This information is summarized below. The Class V Area Permit contains logging requirements to verify the presence and thickness of the upper and lower confining zones. If the well logging information provided to the EPA does not confirm the existence of confining zones for the injection interval at the location of each injection well, the EPA will not issue the Authorization to Commence Injection for that well.

3.3.1 The Upper Confining Zone for Minnelusa Injection Zone

The Opeche Shale is the upper confining zone immediately overlying the Minnelusa injection zone; however, the lithology of the formations overlying the Opeche Shale up to the Sundance Formation causes them to act as suitable confining zones to the Minnelusa (Green, 1993[5]). The thickness values for the Opeche Shale confining zone are based on logs from drillholes located at and near the Dewey-Burdock site. There are 11 oil and gas test wells located in or near the Dewey-Burdock Project Site that intersect the Opeche Shale. Nine of these test wells provide information about the thickness of the Opeche Shale. Based on information from these nine wells, the Opeche Shale ranges in thickness from 70 to 113 feet. The Area Permit requires Powertech to collect information during the drilling of the Class V injection wells to document and confirm the presence of the overlying confining

[5] Greene, 1993.

zone. The EPA will evaluate logs from DW No. 1 and DW No. 3 deep Class V injection wells to verify the thickness of the Opeche Shale at the location of the injection wells.

3.3.2 The Lower Confining Zone for Minnelusa Injection Zone

The Lower Minnelusa Formation is the lower confining zone for the Minnelusa injection zone, hydraulically separating it from the underlying Madison Formation. Information about the thickness of the Lower Minnelusa Formation at the Dewey-Burdock Project Site is available from the detailed lithologic description of the Minnelusa Formation in the log of the Sun #1 Lance Nelson oil and gas test well that was drilled into the Madison Formation. This oil and gas test well is located about 2,400 feet to the southwest of DW No. 1 in the Burdock area. At this location, the Lower Minnelusa confining zone is 558 feet thick if the injection zone does not go deeper than the 2nd Leo sand. The Class V Area Permit allows Powertech to drill deeper into the Minnelusa Formation to investigate the permeability in the 3rd Leo sand. The Class V Area Permit allows Powertech to extend the injection zone downward if Powertech finds that the 3rd Leo sand is permeable. The 3rd Leo sand may be up to 250 deeper than the 2nd Leo sand. Even if the Minnelusa injection zone is extended downward the additional 250 feet, the Lower Minnelusa confining zone is still about 308 feet thick in this area based on the log of the Sun #1 Lance Nelson oil and gas test well.

To obtain information on the lower confining zone, the Area Permit requires Powertech to provide information from the drilling and logging of the Madison water supply wells , if they are approved by the South Dakota Water Rights Program. Because the Madison water supply wells will be drilled into the Madison Formation, they will intersect the Lower Minnelusa Formation, which is the lower confining zone for the Minnelusa injection zone. The locations of the Madison water supply wells are shown in Figures 4a and 4b. If the South Dakota Department of Natural Resources and Environment (DENR) Water Rights Program does not approve the Madison water supply wells, then the Part II, Section E.1.d of the Class V Area Permit requires Powertech to drill an additional 50 feet into the top of the Lower Minnelusa confining zone and conduct a formation integrity test to ensure the Lower Minnelusa confining zone is able to provide confinement under the MAIP the injection pressure. The EPA has reviewed the well logs for the oil and gas test wells located within the Class V permit Area of Review. Although the Sun #1 Lance Nelson oil and gas test well is the only well that was drilled completely through the Minnelusa Formation into the Madison Formation, the eight other oil and gas test wells do penetrate some distance into the Lower Minnelusa Formation and provide evidence of the presence and thickness of the Lower Minnelusa confining zone at the Dewey-Burdock Project Site. The locations of the oil and gas test wells are shown in Class III Permit Application Plate 3.1. Information on the depth each well was drilled and how far into the Minnelusa Formation each well extends is included in Table 10 of the Class III Fact Sheet.

Table 5. Confining Zones

Area	Formation Name	Depth Top (feet)	Depth Base (feet)	Thickness (feet)
Minnelusa Porosity Zone (Burdock)	Upper: Opeche Shale	1,520	1,615	95
	Lower: Base of Minnelusa Formation	2,205 – 2,450	2,765	315 - 560
Minnelusa Porosity Zone (Dewey)	Upper: Opeche Shale	1,855	1,950	95
	Lower: Base of Minnelusa Formation	2,540 – 2,785	3,100	315 - 560

3.3.3 Additional Hydrologic Evaluation of the Lower Minnelusa Confining Zone

Naus et al., 2001[6], state "Low-permeability layers in the lower part of the Minnelusa Formation generally act as an upper confining zone to the Madison aquifer. However, karst features in the top of the Madison Limestone may contribute to reduced competency of the overlying confining zone in some locations." These locations occur north of the Dewey-Burdock Project Site, but not within the Project Site. Figure 11 in Naus et al., 2001, shows the location of a dissolution front, which is also mentioned in Class III Permit Application Appendix E which discusses the location of breccia pipes occurring in the Minnelusa and overlying stratigraphic units 8 to 25 miles north and east of the Dewey-Burdock project boundary. At this dissolution front, the higher elevation potentiometric surface of the Madison aquifer is penetrating into the Minnelusa Formation and dissolving anhydrite beds. North of the dissolution front, the anhydrite beds have been removed and the Minnelusa Formation is much thinner. The Minnelusa aquifer fluids are lower in sulfate because the anhydrite is no long present. At the dissolution front, sulfate concentrations increase in the Minnelusa aquifer fluids because anhydrite is being actively dissolved by up-welling Madison aquifer fluids. South of the dissolution front, where anhydrite beds are still present in the Minnelusa formation, the sulfate concentration is even higher because the aquifer fluids are in chemical equilibrium with the anhydrite in the aquifer formation.

Naus et al., 2001, discuss three ways to further verify the competence of the Lower Minnelusa confining zone at the Dewey-Burdock Project Site based on these observations:

1) Comparing the values of major ion concentrations measured in the Minnelusa and Madison aquifer fluids can indicate whether or not there is hydraulic connection between the two aquifers. Figure 5 shows the major ions that will be used to characterize the Minnelusa and Madison aquifersFigure 35 in Naus et al., 2001, shows plots of the major ion concentrat ions from samples collected from wells pair completed in the Minnelusa and Madison aquifers, respectively. The relative ion concentrations in each aquifer show sufficient difference in chemical signatures to indicate hydraulic separation between the Minnelusa and Madison aquifers at the Dewey-Burdock Project Site. Figure 6 shows the portion of Figure 35 that includes the Dewey-Burdock Project Site. To further confirm that the Lower Minnelusa confining zone provides hydraulic separation between the Minnelusa and Madison aquifers, the Area Permit requires Powertech to collect fluid samples from the Minnelusa aquifer during the drilling of DW No. 1 and DW No. 3 and analyze the samples for the major ions shown in Figures 5 and 6. The Area Permit also requires Powertech to collect fluid samples from both the Minnelusa aquifer and the Madison aquifer during the drilling of the Madison water supply wells, if they are approved by the South Dakota Water Rights Program. The locations of the Madison water supply wells are shown in Figures 4a and 4b.
2) Based on Naus et al., 2001, sulfate concentrations in the Minnelusa aquifer may also be used as an indicator of hydraulic connectivity between the Madison and Minnelusa aquifers. Under conditions of no hydraulic connectivity, the Minnelusa aquifer has much higher sulfate concentrations than the Madison aquifer because of the presence of anhydrite beds. Anhydrite is a mineral composed of calcium and sulfate. The Madison aquifer has low sulfate in comparison to the Minnelusa aquifer. The Madison aquifer has a much higher potentiometric surface than the Minnelusa aquifer. Where there is hydraulic connectivity between the two aquifers, the Madison aquifer fluids flow upwards into the Minnelusa aquifer, dilute the sulfate concentration in the Minnelusa aquifer fluids and, over geologic time, dissolve the anhydrite beds in the Minnelusa. In the Minnelusa aquifer, according to Naus et al., 2001, "Sulfate

[6] Naus et al., 2001. Geochemistry of the Madison and Minnelusa Aquifers in the Black Hills Area, South Dakota

concentrations less than 250 mg/L delineate a zone in which anhydrite probably has been largely removed by dissolution. The zone in which sulfate concentrations are between 250 and 1,000 mg/L marks the position of the 'anhydrite dissolution front,' an area of active removal of anhydrite by dissolution. Downgradient from the anhydrite dissolution front, sulfate concentrations are greater than 1,000 mg/L, which corresponds to a zone in which thick anhydrite beds remain in the Minnelusa Formation." Figure 6 shows that the Minnelusa aquifer in the Dewey-Burdock Project Site is expected to have sulfate concentrations greater than 1,000 mg/L. Analytical results from the Minnelusa aquifer samples required by the Area Permit will document the Minnelusa aquifer sulfate concentration at the Dewey-Burdock Project Site.

3) Observing the difference between the potentiometric surfaces of the Minnelusa and Madison aquifers provides another indication of hydraulic separation between the two aquifers.

Naus et al., 2001, present graphs showing the potentiometric surface elevations of the Minnelusa and Madison aquifers at the two locations shown in Figure 6 for well pairs 215 and 216 (Hell Canyon) and well pairs 242 and 243 (Minnekahta Junction). These graphs are shown in Figure 7. The graphs show that at both locations the potentiometric surface for the Madison Formation is at a higher elevation than the potentiometric surface of the Minnelusa Formation, which indicates there is hydraulic separation between the two aquifers in those two areas. The Area Permit requires Powertech to measure the potentiometric surface of the Minnelusa injection zone and the Madison Formation during the drilling of the Madison Formation water supply wells, if they are approved by the South Dakota Water Rights Program.

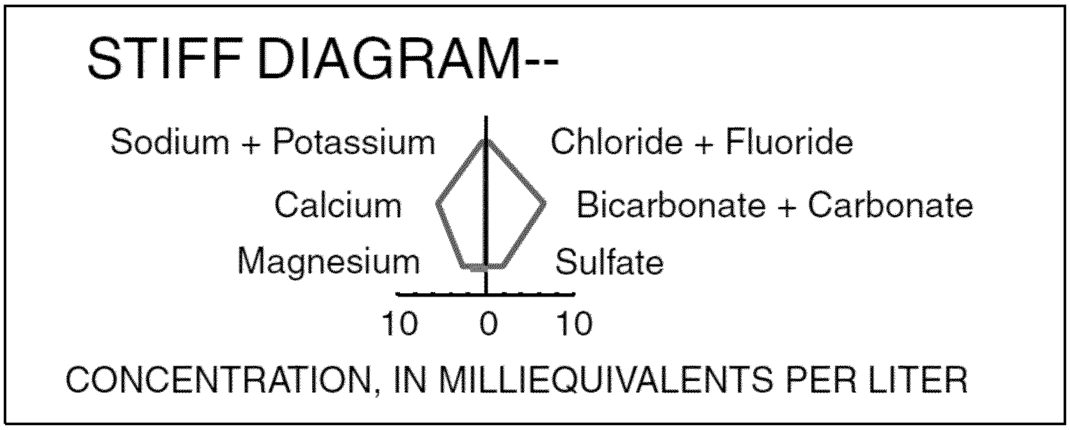

Figure 5. Major Ions that Can Be Used to Characterize the Aquifer Fluids in the Minnelusa and Madison Aquifers

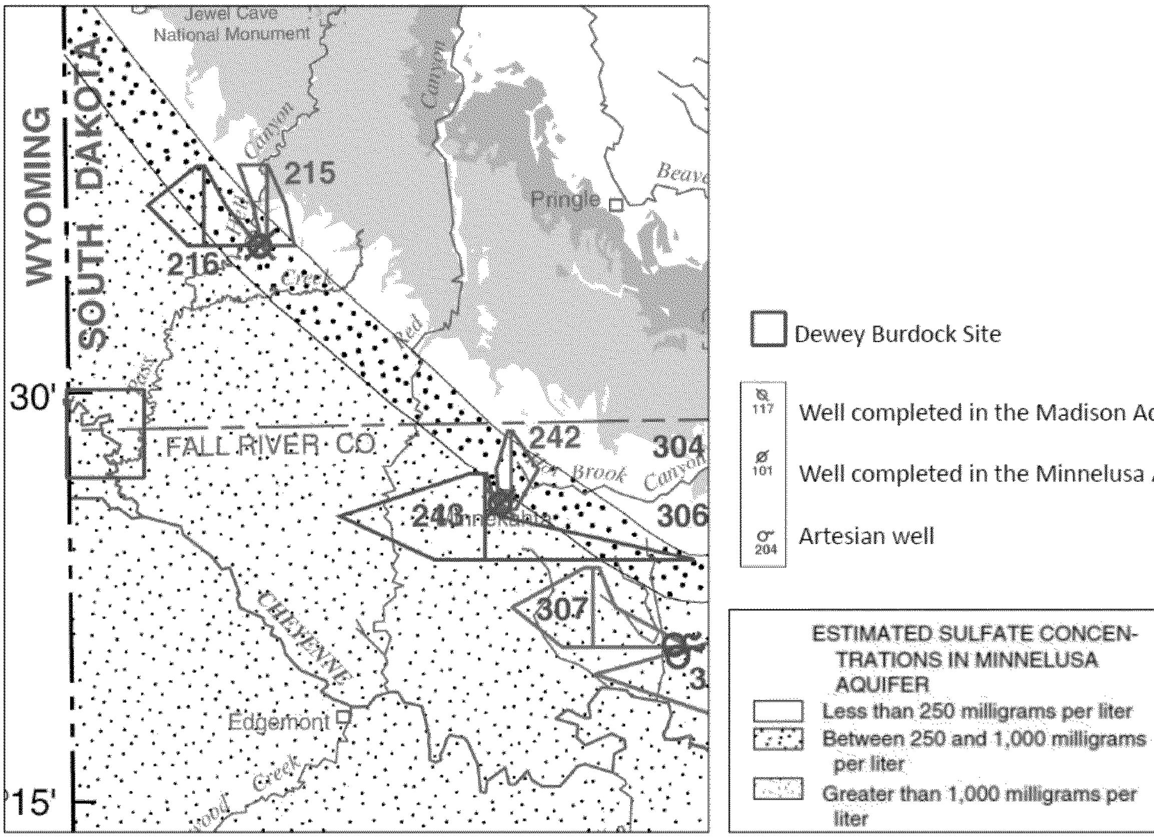

Figure 6. Shapes of STIFF Diagrams that Characterize the Minnelusa and Madison Aquifers, and Estimated Sulfate Concentration in the Minnelusa Aquifer

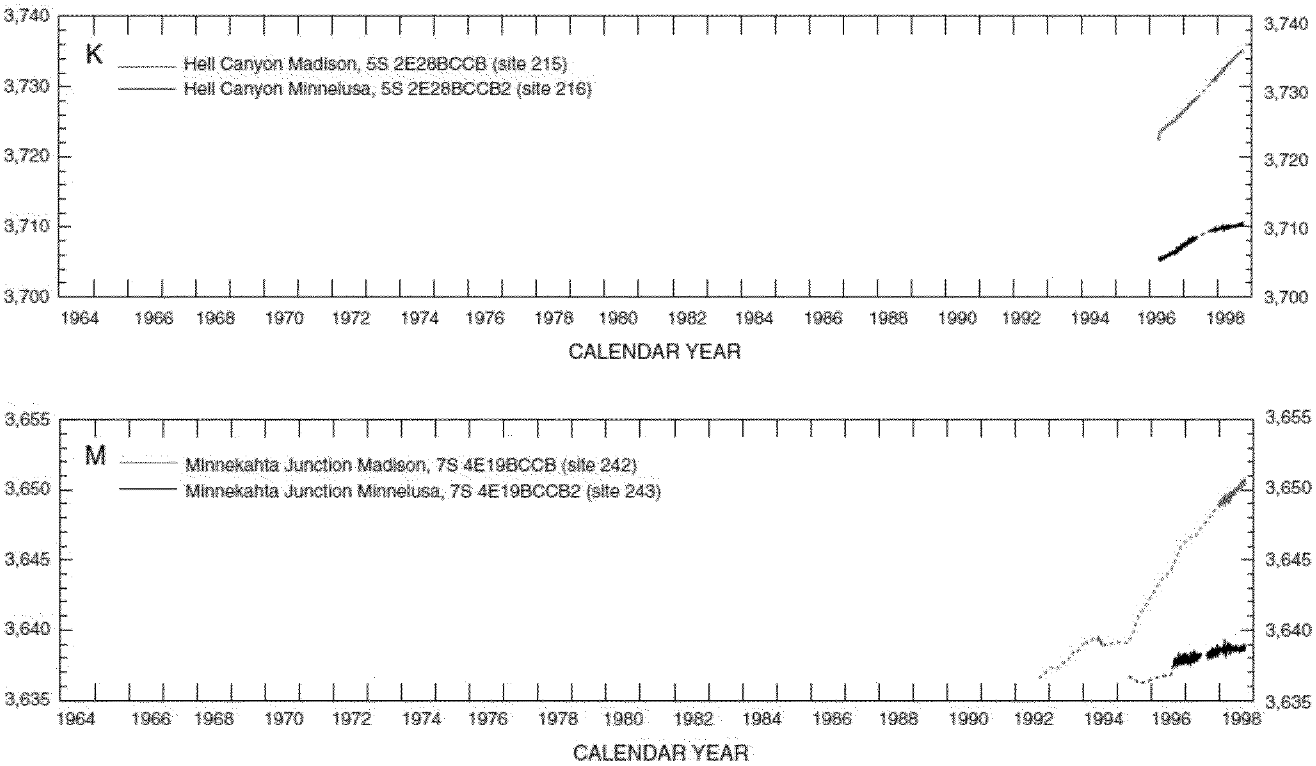

Figure 7. Water Level Measurements in Well Pairs Completed in the Madison and Minnelusa Aquifers (Measurements are shown as elevations above mean sea level)

3.4 Underground Sources of Drinking Water (USDWs)

As stated earlier, under 40 CFR § 144.3 *Underground source of drinking water (USDW)* means an aquifer or its portion:

(a)(1) Which supplies any public water system; or

(2) Which contains a sufficient quantity of ground water to supply a public water system; and

(i) Currently supplies drinking water for human consumption; or

(ii) Contains fewer than 10,000 mg/l total dissolved solids; and

(b) Which is not an exempted aquifer.

The known USDWs at the Dewey-Burdock Project Site are identified in Table 6.

Table 6. Underground Sources of Drinking Water (USDWs)

Formation Name	Burdock Area		Dewey Area		Lithology	TDS (mg/L)
	Top (feet)	Base (feet)	Top (feet)	Base (feet)		
Alluvial Deposits	0	50	0	30	Alluvium (poorly sorted, unconsolidated silt, clay, sand and gravels)	5285
Inyan Kara Group Fall River Formation ISL Lakota Formation Chilson Sandstone ISL	 140 350	 300 425	 440 625	 580 705	Interbedded fluvial sandstones and shale	 1275 1263
Unkpapa Sandstone	560	640	825	900	Sandstone	1375
Sundance Formation	640	920	900	1180	Shale, sandstone, thin beds of limestone Basal sandstone	1375
Madison Formation	2765	3060	3100	3395	Limestone and dolomite The Madison aquifer occurs within the top 100 to 200 feet[7]	690 - 1333

[7]Greene, 1993.

The Minnekahta Limestone is identified as an aquifer in the Black Hills area in Powertech's Class V and Class III Permit Applications, Naus et al., 2001, and the U.S. Geological Survey Hydrologic Investigations Atlas HA-744-B. The Minnekahta Limestone serves as an aquifer only locally where it occurs at or near the ground surface. The fine-grained nature of limestone results in low porosity and very low permeability, which causes it to be a confining unit rather than an aquifer. When limestone occurs at or near the ground surface, interaction with precipitation and fresh groundwater near outcrop areas over geologic time causes the limestone to dissolve and karst features to develop within the limestone unit . The Madison Limestone was exposed at the surface for approximately 50 million years. Complex and interconnected solution features developed in the Madison Limestone during tropical conditions when it was exposed at or near land surface[8] before the Minnelusa Formation was deposited on top of it. It is these solution features that create the permeability within the Madison Formation that cause it to be an aquifer. Unlike the Madison Limestone, the Minnekahta Limestone was not exposed at the surface before the Spearfish Formation was deposited on top of it. Where the Minnekahta Limestone now occurs at or near the ground surfaceand solution features have begun to develop, increasing permeability and enabling it to provide water in these limited areas. Where the Minnekahta is described in the oil and gas test well logs, no porosity is mentioned.

[8] Busby et al., 1995. Geochemistry of water in aquifers and confining units of the NorthernGreat Plains in parts of Montana, North Dakota, South Dakota, and Wyoming.

In the Class V Project Area, where the Minnekahta Limestone occurs at a depth of 1,400 to 1,800 feet below ground surface, its fine-grained lithology causes it to be a confining unit rather than an aquifer. At the Dewey-Burdock Project Site the Minnekahta Limestone is more similar to the Englewood Formation, which is also a limestone that serves as part of the lower confining zone for the Madison aquifer. If the Minnekahta were a USDW capable of supplying groundwater to a public water system, the City of Edgemont would likely have tapped it for their public water supply instead of drilling approximately 1,300 feet deeper to the Madison Formation.

To verify the lack of water-bearing capacity of the Minnekahta Formation at the Dewey-Burdock Project Site, the Area Permit requires Powertech to measure the potentiometric surface of Minnekahta Formation aquifer fluids at each injection well site. If the potentiometric surface of Minnekahta Formation fluids is not higher than the formation top, then it is not a USDW because it would not yield enough water to supply a public water system. If the potentiometric surface of the Minnekahta aquifer fluid is above the top elevation of the formation, then the Area Permit requires Powertech to attempt to collect aquifer fluid samples to analyze for TDS. Before fluid samples can be collected from an aquifer, the Area Permit requires water to be pumped from the aquifer until field parameter measurements stabilize in order to be sure the fluid sample collected is representative of the aquifer fluids. If the Minnekahta Formation is not able to sustain pumping rates necessary to obtain representative samples of the aquifer fluids, then the Minnekahta Formation is not a USDW because it does not contain a sufficient quantity of ground water to supply a public water system.

The Unkpapa and Sundance Formations are identified as separate USDWs in Table 6. However, apparently there is no continuous confining unit separating them at the Dewey-Burdock Project Site, so they are hydraulically connected. For this reason, they are referred to as the "Unkpapa/Sundance USDW" throughout the rest of this document.

4.0 AREA OF REVIEW EVALUATION AND CORRECTIVE ACTION PLAN

4.1 Area of Review Definition and Purpose

Area of review (AOR) means the area surrounding an injection well described according to the criteria set forth in 40 CFR § 146.06 or in the case of an area permit, the Project Area plus a circumscribing area the width of which is either 1/4 of a mile or a number calculated according to the criteria set forth in § 146.6.

As part of the review for this Area Permit, UIC regulations require Powertech to perform an AOR determination, which involves an investigation of the AOR for any features that would compromise the confining zones that are necessary to contain the injected fluids within the authorized injection interval.

4.2 Faults

Review of geologic studies of the Dewey-Burdock area did not indicate the presence of any faults within the Dewey-Burdock Project Area (the Dewey Geologic Quadrangle[9] and the Burdock Geologic Quadrangle[10]). Two major fault zones occur to the northwest and the southeast of the Project Area.

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[9] Geology of the Burdock Quadrangle Fall River and Custer Counties, South Dakota.

[10] Geology of the Dewey Quadrangle Wyoming-South Dakota.

The Dewey structural zone consists of steeply dipping to vertical faults that are uplifted on the north side relative to the south side of the zone a total of 500 feet. The fault zone is visible for 13 miles extending northeastward across the Dewey and Jewel Cave SW quadrangles.

The Long Mountain structural zone is located approximately 7 miles south of the Project Area. This fault zone consists of small northeast-trending normal faults observed in outcrops of the Inyan Kara Group and Sundance Formation within a zone measuring several miles across. Along the north edge of the Long Mountain structural zone the strata are dropped down on the south side of the faults. The displacement across the faults measures up to 40 feet, with folding of the strata adjacent to the faults adding up to 60 feet of additional structural relief.

Faults are shown on the Dewey and Burdock geologic quadrangles and described in the corresponding reports. The faults in the Dewey Quadrangle occur northwest of the Dewey Fault in the Dewey Terrace area approximately 1.5 miles northwest of the Project Area. A subsurface fault was identified by seismic methods about 5.5 mile north of the Project Area boundary. This fault zone is about 1.5 miles long and 400 feet wide.

Three faults are shown in the northeast corner the Burdock Geologic Quadrangle. The report states that these faults have a displacement of less than 10 feet. These faults are 2.5 miles and greater from the eastern edge of the Project Boundary.

4.3 Plugged Oil and Gas Test Wells

There are three oil and gas test wells present within the Dewey-Burdock Project Site. Information about these three wells is presented in Table 7. Plugging information is available for all three wells.

Table 7. Oil and Gas Test Wells Located within the Dewey-Burdock Project Boundary.

Well Name	API No.	Location	Total Depth (feet bgs)	Formation at Total Depth	Plugging Info Available?
Well log Well name: Dolezal 1 Darrow Well name in Class V Permit App: Earl Darrow #1	4004705095	SESE Sec 2 T7S R1E	2450	Minnelusa	Yes
ARC 34-11 Peterson	4004720071	SWSE Sec 11 T7S R1E	2250	Minnelusa	Yes
PRC 21-14 Peterson	4004720065	NENW Sec 14 T7S R1E	2284 plugged back total depth to 850 feet	Fall River[11]	Yes

[11] The Minnelusa Formation was the original target zone for the well. Records show the Well was plugged near base of Sundance Formation to use as a stock water ing well. Recent field measurement determined current well depth to be 175 feet, which is in the Fall River Formation.

4.4 AOR Evaluation

Powertech used three types of calculations to evaluate the impact of injection activities on the injection zone aquifers and USDWs near the injection well locations as part of the AOR evaluation for the proposed Class V injection wells. The three types of calculations are the critical pressure rise, injection zone pressure diffusivity with distance from injection well, and radius of fluid displacement calculations. The purpose of these calculations is to determine a distance from each injection well site that injection fluid and pressure have the potential to impact the injection zone and USDWs.

4.4.1 Injection Zone Critical Pressure Rise Calculation

The injection of fluids into an injection zone raises the fluid pressure inside the injection zone. If there is a breach in the confining zones for the injection zone, the pressure within the injection zone would act to move fluids out of the injection zone along the pathway created by the breach in the confining zone. The factor that determines if injection zone fluids leave the injection zone through a hypothetical pathway through the confining zone is whether or not the pathway is connected to an overlying or underlying aquifer that has a lower fluid pressure than the fluid pressure in the injection zone. The fluid pressure in an aquifer can be measured by the distance the potentiometric surface rises above the top of the aquifer unit. The Madison aquifer is known to have a higher fluid pressure than the Minnelusa aquifer in the southern Black Hills region.[12,13] Proposed activities at the Dewey-Burdock Project Area, such as injection activity into the Minnelusa aquifer and groundwater use from the Madison aquifer, will change the respective aquifer pressures. Therefore, it is important to calculate the fluid pressures in each of these aquifers and determine the critical pressure rise in each injection zone that will move injection zone fluids into adjacent aquifers through a hypothetical pathway in a confining zone.

In the case of the Minnelusa injection zone, the two adjacent aquifers are the overlying Unkpapa/Sundance USDW and the underlying Madison USDW. Powertech calculated the following critical pressures at the Dewey and Burdock Areas:

1) The critical pressure within the Minnelusa porosity zone required to move fluids up into the first overlying USDW, the Unkpapa/Sundance aquifers; and
2) The critical pressure within the Minnelusa porosity zone required to push fluids downward into the Madison aquifer.

These calculated critical pressures are presented in Table 8. The Powertech calculations are found on pages 2-2 through 2-7 of the Class V Permit Application.

The EPA did not agree with some of the assumptions that Powertech used for calculations involving the Madison USDW and recalculated the critical pressure values involving the Madison Formation. The EPA interpolated the depth to the Madison USDW potentiometric surface to be 15 feet below ground surface elevation in the Burdock Area and right at ground surface elevation in the Dewey Area based on interpretation of Figure D-10 in the Class V Permit Application; Powertech placed the Madison potentiometric surface 200 feet above ground level at both areas. The Madison USDW potentiometric surface will be drawn down by the proposed Madison water supply wells that Powertech will install at the Dewey-Burdock Project Site, if the Madison water rights are approved by the South Dakota Water Rights Program. The South Dakota Water Rights Program *Report to the Chief Engineer on Water Permit Application No. 2685-2* calculated the drawdown in the Madison aquifer potentiometric surface from the Madison water supply wells to be 86.8 feet at the well locations within the Dewey-Burdock Project Area. The EPA used the DENR drawdown depth of 86.8 feet affecting the Madison aquifer potentiometric surface in the critical pressure calculations involving the Madison aquifer. Powertech did not include any drawdown of the

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[12] Naus et al., 2001.

[13] Carter et al., 2003. Ground-Water Resources in the Black Hills Area, South Dakota.

Madison potentiometric surface in the critical pressure rise calculations. Taking into account a lower aquifer pressure within the Madison resulting from pumping of the Madison water supply wells, the EPA calculated a lower critical pressure rise than Powertech for the movement of fluids out of the Minnelusa injection zone downward into the Madison aquifer as shown in Table 8. Therefore, according to the EPA calculations, less pressure is needed within the injection zone to move injection zone fluids upward into the Minnelusa aquifer than the pressure calculated by Powertech. The EPA critical pressure calculations are shown in the spreadsheet entitled *EPACriticalPressureCalculations.xls x* which is included in the Administrative Record for this permitting action.

Table 8. Calculation of Critical Pressure Needed in the Minnelusa Injection Zone to Move Injection Zone Fluids along a Hypothetical Pathway through the Confining Zone into a USDW

Site	Injection Zone	USDW	Powertech Critical Pressure Calculations (psi)	EPA Critical Pressure Calculations (psi)
Burdock	Minnelusa Porosity injection zone	Unkpapa/Sundance USDW	97.1	97.1
	Minnelusa Porosity injection zone	Madison USDW	165.6	34.8
Dewey	Minnelusa Porosity injection zone	Unkpapa/Sundance USDW	96.1	96.1
	Minnelusa Porosity injection zone	Madison USDW	164.6	40.3

Part II, Section F.1 of the Class V Area Permit requires Powertech to recalculate the critical pressure rises for each injection zone based on the site-specific information collected during the construction of each well. This site-specific information is discussed in Section 5.0.

4.4.2 Calculation of Injection Zone Pressure Rise Resulting from Injection Activity

Powertech also calculated the rise in aquifer pressure in Minnelusa injection zone that would result from 10 years of injection activity at an injection rate of 75 gallons per minute (gpm) at the Burdock and Dewey Sites. This pressure would be highest at the injection well location and decrease away from the injection well according to a radial flow diffusivity equation found on page 2-4 of the Class V Permit Application. Figure 8 illustrates this pressure dynamic.

Powertech used this information to evaluatethe distance from each injection well where the injection-induced formation pressure would be greater than or equal to the critical pressure needed to move injection zone fluids into USDWs. Pressure values and radius distances for Powertech's calculation are presented in Class V Permit Application Tables A-3 for the Minnelusa injection zone.

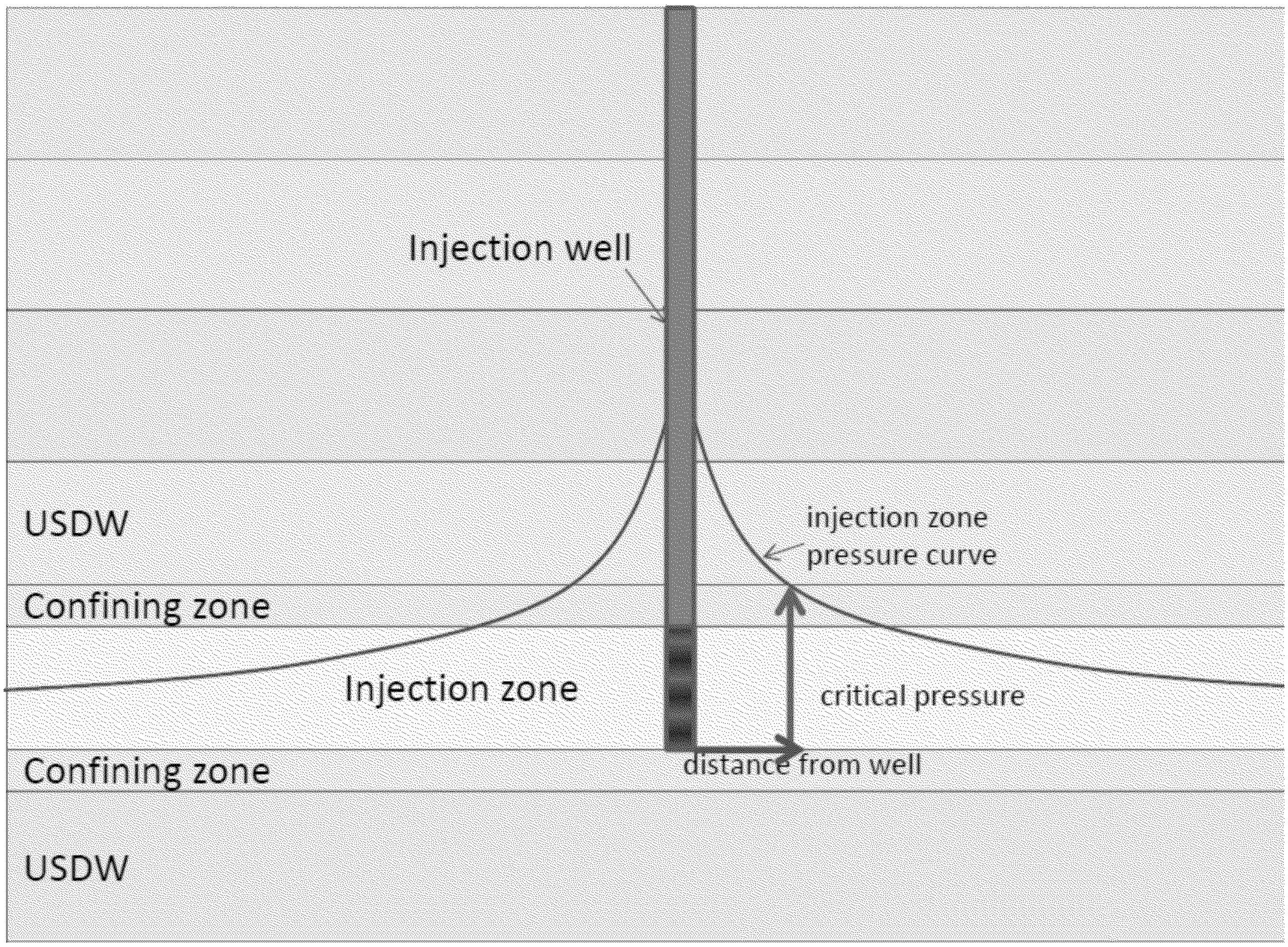


Figure 8. Fluid Pressure Rise within Injection Zone as a Result of Injection Activity

4.4.2.1 Minnelusa Injection Zone Pressure and the Unkpapa/Sundance USDW

It is important to compare the Minnelusa injection zone pressure with the critical pressure rise needed to move fluids from the Minnelusa injection zone into the overlying Unkpapa/Sundance USDW. There are three historic oil and gas test wells in the Burdock Area that either pass through, or are completed in, the Minnelusa Formation. The closest oil and gas test well penetrating the Minnelusa is the Earl Darrow #1 located approximately 3,900 feet away from the proposed location for the Burdock Area Class V deep injection well DW No. 1. Similarly, the nearest potential pathway for fluid movement out of an injection zone in the Dewey Area is the Dewey Fault, which is located 9,375 feet northwest of the proposed location for the Dewey Area Class V deep injection well DW No. 3. Comparing injection-inducted pressure within the injection zone as it changes with distance from each injection well with the critical pressure rise needed to move injection zone fluids up into the Unkpapa/Sundance USDW will determine if the historic oil and gas test wells or the Dewey Fault are potential pathways for injection zone fluid movement.

Powertech calculated the distance away from each Class V deep injection well where the Minnelusa injection zone pressure value would be greater than the calculated critical pressures values. The three oil and gas test wells in the Burdock Area were drilled into or below the Minnelusa Formation through the Opeche Shale and other overlying confining zones located between the Minnelusa injection zone and the overlying Unkpapa/Sundance USDW. Although plugging records are available for these three wells, Powertech decided not to rely on these plugging records as a guarantee that the wells do not present a potential pathway for fluid migration from the Minnelusa injection zone to the overlying Unkpapa/Sundance USDW. According to Powertech's calculations, the formation pressure in the Minnelusa injection zone as a result of injection activity is above the critical pressure needed to move fluids upward into the Unkpapa/Sundance USDW for only a distance of less than 15 feet from both Minnelusa injection well locations in both the Dewey and Burdock Areas, as shown in Table A-3 of the Class V Permit Application. Based on these calculations, the Class V disposal wells in the Burdock Area are located far enough away from the three oil and gas test wells in the Burdock area to prevent the injection-induced pressure in the Minnelusa injection zone from being high enough to cause migration of Minnelusa injection zone fluids through any pathways that might exist at these oil and gas test wells upward to the Unkpapa/Sundance USDW. The Class V disposal wells in the Dewey Area are located far enough away from the Dewey Fault to prevent the injection-induced pressure in the Minnelusa injection zone from being high enough to cause migration of Minnelusa injection zone fluids upward along the Dewey Fault.

Figure 9 shows the projected construction, operation and restoration schedule for the whole Dewey-Burdock ISR project. The schedule shows well field restoration occurring through the 1st quarter of the 9th year of operation. Once restoration of all wellfields is complete, there will be no further wellfield bleed to be disposed of in the Class V deep wells. The EPA used 12 years as a conservative estimate for how long the deep Class V injection wells will be operating through the end of ISR well field groundwater restoration and conservatively used 12 years of injection activity as the input value for the radial flow diffusivity equation rather than the 10 years used by Powertech.

Section 7.7.1 provides a detailed explanation of the water balance for the Dewey-Burdock Project. The total volume of waste fluids that will be disposed of in the deep injection wells is expected to be 232 gpm. If four disposal wells are used, the average maximum injection rate that would be required at each well is 58 gpm. Anticipating four injection wells, Powertech used a flow rate of 75 gpm in its calculations. The Class V Draft Area Permit allows up to four wells injecting into the Minnelusa

The EPA recalculated the radius from each Class V injection well where Minnelusa injection–induced pressure is greater than the critical pressure to move Minnelusa injection zone fluids upwards into the Unkpapa/Sundance USDW. The EPA calculation used 12 years of injection activity, a flow rate of 116 gpm and information from Greene, 1993, indicating that the measured porosity of the Upper Minnelusa aquifer is 10% at a well near Rapid City. Using these input values, the calculated radius for from DW No. 1 in the Burdock Area is 475 feet. Powertech's calculated radius for the DW No. 1 is 13.2 feet using 10 years of injection activity and 21% porosity, which is a reasonable porosity estimate for a typical sandstone, and a flow rate of 75 gpm. The EPA calculated radius for the DW No. 3 in the Dewey Area is 500 feet, compared with Powertech's calculated radius of 14.4 feet using 10 years of injection activity, 21% porosity and a flow rate of 75 gpm. The EPA diffusivity calculations are shown in the spreadsheet entitled *EPADiffusivityCalculations.xlsx* which is included in the Administrative Record for this permitting action. The plugged and abandoned oil and gas test well, Earl Darrow #1, is located 3,900 feet away from the DW No. 1, the Class V injection well in the Burdock Area. The Earl Darrow #1 penetrated the Unkpapa/Sundance and Upper Minnelusa Formation aquifers, and, therefore, potentially provides a pathway through the confining zones connecting these two aquifers. Using 12 years of injection activity, 10% porosity and a 116 gpm flow rate in the diffusivity calculation, the DW No. 1 is located far enough away from the Earl Darrow #1 in the Burdock Area to prevent injection-induce pressure from being high enough to cause Minnelusa injection zone fluids to move upward through the Earl Darrow #1 well and into the Unkpapa/Sundance USDW. The Dewey fault is located 9,375 feet from the DW No. 3, the Class V injection well in the Dewey Area. Using 12 years of injection activity, 10% porosity and a 116 gpm flow rate in the diffusivity calculation, the DW No. 3 is located far enough away from the Dewey Fault in the Dewey Area to prevent injection -induce pressure from being high enough at the Dewey Fault to cause Minnelusa injection zone fluids to move upward to the Unkpapa/Sundance USDW.

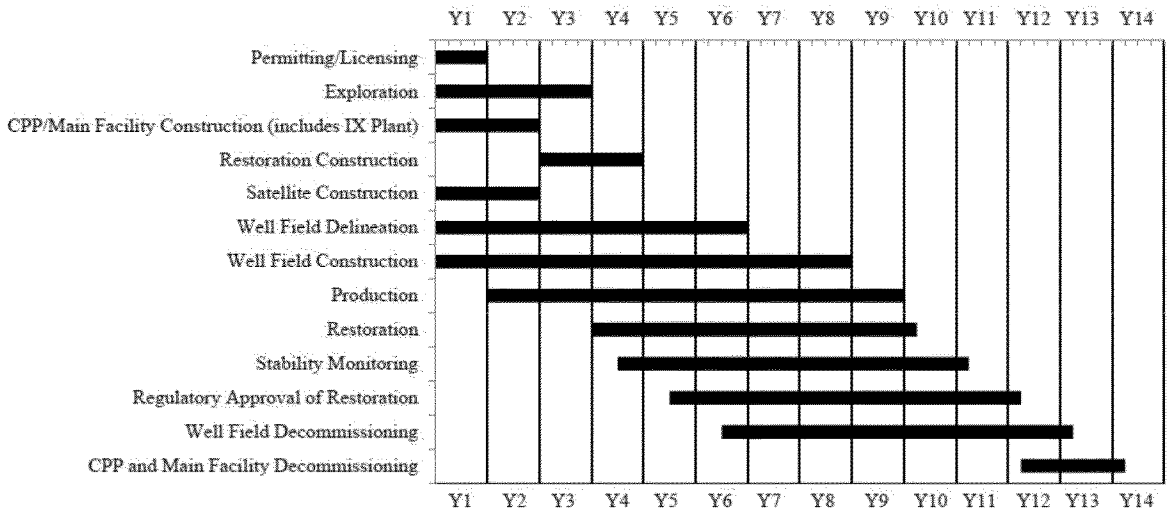


Figure 9. Projected Construction, Operation and Decommissioning Schedule at the Dewey-Burdock Project Site

Part II, Section F.1 of the Area Permit requires Powertech to recalculate the critical pressure rises for the Minnelusa injection zone and Part II, Section F.2 requires the calculation of the injection-induced formation pressure values with distance away from each Class V disposal well based on the site -specific information collected during well construction. This site-specific information is discussed in Section 5.0. The Class V Area Permit requires the injection-induced formation pressures to be calculated based on 12 years of injection activity and the maximum average injection rate per well that will be required to dispose of the maximum anticipated volume of ISR waste fluids. The maximum anticipated volume of ISR waste fluids for which disposal is required is expected to be 232 gpm. This means that each Class V disposal well will need to dispose of 116 gpm.

4.4.2.2 Minnelusa Injection Zone Pressure and the Madison USDW

The critical pressures in the Minnelusa injection zone that would move fluids into the underlying Madison Formation, as calculated by the EPA, are 34.8 psi in the Burdock Area and 40.3 psi in the Dewey Area. According to the EPA diffusivity calculations using 12 years of injection activity, 10% porosity and a 116 gpm flow rate in the diffusivity calculation, the distance from DW No. 1 in the Burdock Area where the injection zone pressure would be above the critical pressure is 18,480 feet (3.5 miles). In the Burdock Area the Sun #1 Lance Nelson oil and gas test well penetrated all the way through the Minnelusa Formation and 67 feet into the Madison Formation. This is the nearest potential pathway between the Minnelusa injection zone and the Madison Formation. The Sun #1 Lance Nelson is located approximately 17,250 feet southwest of the DW No.1. At this distance away from the Class V injection wells, the pressure within the Minnelusa injection zone resulting from injection activity is **not** below the critical pressure needed to move fluids out of the Minnelusa injection zone into the Madison Formation.

According to the EPA diffusivity calculations using 12 years of injection activity, 10% porosity and a 116 gpm flow rate in the diffusivity calculation, the distance from the DW No. 3 in the Dewey Area where the injection zone pressure would be above the critical pressure for moving fluids into the Madison Formation is 13,200 feet (2.5 miles) from the injection well location. The Sun #1 Lance Nelson test well is located approximately 27,750 feet from DW No.3. The Dewey Fault is located approximately 9,375 feet from the DW No.3. The Dewey Fault **not** is far enough away from DW No. 3 to prevent injection-induced pressure from moving injection zone fluids downward into the Madison USDW.

The EPA also calculated a maximum injection rate that would not cause the injection -induced pressures in the Minnelusa injection zone to be above critical pressure within 1,000 feet of the Dewey Fault and the Sun #1 Lance Nelson. These maximum injection rates are 110 gpm for the DW No. 1 and 97 gpm for DW No. 3. These calculations can be reviewed in the file entitled: *EPADiffusivityCalculations_Final.xlsx*, which is a part of the Administrative Record for these UIC permitting actions. If Powertech installed a third well in the Minnelusa injection zone, the average maximum injection rate that would be needed for three wells to dispose of 232 gpm of ISR waste fluids is 77.33 gpm. Basedon these calculations, it appears that Powertech may need to install a third Minnelusa Class V injection well to dispose of the total expected volume of fluid waste and to prevent injection-induced pressure from moving injection zone fluids downward into the Madison USDW.

Powertech will drill the two Class V injection wells and determine the actual thickness of the Minnelusa injection zone from well logging and the actual porosity for laboratory testing of core. These parameters are input values into the diffusivity equation. Using site-specific data as input into the diffusivity equation will provide the site-specific estimates of the decline of injection-induced pressure within the injection zone with distance away from each injection well. As stated earlier, the Class V Area Permit requires Powertech to recalculate the critical pressures for each injection zone based on site specific data. The Class V Area Permit also requires Powertech to recalculate the diffusivity equations for each injection zone based on site specific data, such as porosity, 12 years of injection activity and the actual injection rate that will be used at the well. Part II, Section F.3 of the Class V Area permit also requires Powertech to calculate maximum injection rates for each well that will not result in the critical pressure exceedance 1,000 feet away from the nearest pathway through the confining zones. The EPA will review these maximum injection rates and set an injection rate permit limit low enough to maintain the injection zone fluid pressure to below the critical pressure. The injection rate permit limit is discussed in Section 7.7.

4.4.3 Calculation of Radius of Fluid Displacement in the Minnelusa Injection Zone

The third calculation Powertech performed is the radius of fluid displacement for each injection well. The radius of fluid displacement is the distance the injectate is expected to travel away from the injection well based on injection rate, injection zone thickness, and porosity. Powertech's calculat ion of radius of fluid displacement for the Minnelusa injection zone is presented in Table A-5 of the Permit Application.

A reliable estimated radius of fluid displacement within the proposed Minnelusa injection zone can be calculated by using the volume of injectate, the vertical thickness of sandstones within the proposed injection zone and a porosity value to represent the amount of open pore space available within the sandstone to receive and store the injected fluids. Powertech estimated the thickness of sandstones to be 164 feet in the Minnelusa porosity zone and an average porosity value of 21%, which is an average porosity value for a typical sandstone. Powertech also added in the downgradient travel distance that would result from the displacement of hydraulic gradient of groundwater flow independent of injection activity.

Powertech calculated a radius of fluid displacement of 706 feet for the Minnelusa Formation injection zone based on 10 years of injection activity. As discussed earlier, the EPA used 12 years of injection activity as the input value and a porosity of 10% for the Minnelusa injection zone.

The EPA performed the radius calculation using an injection rate of 116 gpm per each Class V injection, which is the average maximum injection rate that would be required for each of two (2) Minnelusa injectionwells to dispose of the maximum anticipated volume of waste fluids as discussed in Section 4.4.2.1. After 12 years of injection activity the injectate volume is 97,872,715.4 cubic feet. The distance away from injection wells DW No.1 and DW No. 3 this volume of injectate is expected to travel is 1,399 feet, assuming a homogeneous sandstone porosity of 10%. The EPA calculation of radius of fluid displacement in the Minnelusa injection zone is shown in the spreadsheet entitled *RadiusFluidDisplacement.xlsx* .

4.4.4 AOR Determination

The purpose of performing the calculations described above is to determine the extent of the area within each injection zone that is impacted by injection activity so the area can be investigated for features that could serve as pathways across confining units between the injection zone and USDWs. Table 9 contains a summary for each USDW showing calculated distances the injection-induced pressure within the Minnelusa injection zone exceeds the critical pressure needed to move fluids out of the injection zone into the USDW, compared with the distances between the injection wells and the nearest features that could provide potential pathways for fluid migration out of the injection zone.

Table 9. Summary of Calculated Distances Based on 12 Years of Injection Activity, 10% Porosity at Injection Rate of 116 gpm.

Description	Distance value	Distance to nearest feature that could impact USDWs	Implications
Distance critical pressure in Minnelusa injection zone could move fluids upward into the Unkpapa/Sundance USDW	475 feet at DW No. 1 Burdock Area 500 feet at DW No. 3 Dewey Area	Earl Darrow #1 oil and gas test well which penetrated into Minnelusa is 3,900 feet away from the Class V injection well in the Burdock Area. The Dewey Fault is located 9,375 feet from the Class V injection well in the Dewey Area.	There is very low risk that Minnelusa injection zone fluids will rise upward into the Unkpapa/Sundance USDW at either well location.
Distance critical pressure in Minnelusa injection zone could move fluids downward into the Madison USDW	18,480 feet in the Burdock Area 13,206 feet in the Dewey Area	Sun #1 Lance Nelson oil and gas test well, which penetrated into the Madison Formation, is located 17,250 feet from the Class V injection well in the Burdock Area. The Sun #1 Lance Nelson is located approximately 27,750 feet from the Dewey Area Class V injection well. The Dewey Fault is located 9,375 feet from the Class V injection well in the Dewey Area.	Using an injection rate of 116 gpm, there is very high risk that Minnelusa injection zone fluids will move downward into the Madison USDW at both well locations. The critical pressure and diffusivity calculations should be performed again once site specific information is available for the Minnelusa and Madison aquifers.

In fulfilling the requirements under Part II of the Class V Area Permit, Powertech will determine t he actual, site-specific sandstone thicknesses and potentiometric surface for the proposed Minnelusa injection zone during the drilling, logging, and sampling of each Class V deep injection well. Porosity values will be determined from core drilled through the Minnelusa injection zone. The Class V Area Permit requires Powertech to determine the Minnelusa and Madison aquifer thickness and potentiometric surface elevations at the Madison water supply well. Once this site-specific information is known, Part II, Section E.3.b.i of the Class V Area Permit requires Powertech to perform the drawdown calculation to determine potentiometric surface of the Madison aquifer at the Dewey-Burdock site after 12 years of pumping the Madison water supply wells. The Class V Area Permit requires these site-specific values to be used in the critical pressure rise calculations for the Minnelusa injection zone and the Unkpapa/Sundance and Madison USDWs.

If Powertech decides to construct additional injection wells, Part II, Section F.4 the Class V Area Permit requires that the cumulative pressure effects be determined. Powertech must demonstrate that the cumulative pressure impacts will not cause injection zone fluids to move into adjacent USDWs.

The Class V Area Permit requires Powertech to recalculate the diffusivity equation using sitespecific input values to determine the distance from each injection well the injection–induced injection zone pressure will be above the site-specific critical pressures. These site-specific values diffusivity calculations will also be used to set a maximum injection rate permit limit for each injection zone at each injection well as discussed in Section **7**.

EPA will recalculate the radius of fluid displacement for each injection well based on site-specific information to compare the extent of the radius of fluid displacement for each injection well that lies within the Class V Project Area.

4.5 Corrective Action Plan

UIC regulations found at 40 CFR § 144.55 state the corrective action requirements for protecting USDWs during injection activity. Applicants for Class I, II, (other than existing), or III injection well permits shall identify the location of all known wells within the injection well's AOR which penetrate the injection zone. For such wells which are improperly sealed, completed, or abandoned, the applicant shall also submit a plan consisting of such steps or modifications as are necessary to prevent movement of fluid into USDWs ("corrective action"). Due to the nature of the activity, the EPA is applying requirements consistent with Class I well construction and monitoring standards to the Dewey-Burdock Class V injection wells to protect adjacent USDWs. Because the Class V Permit Area does not include the three oil and gas test wells in Table 7, there are no wells within in the AOR that penetrate the Minnelusa injection zone. This Class V Area Permit includes requirements to assure injection-induced pressures within the Minnelusa injection zone will not exceed critical pressure required to move fluids out of the injection zone at the Dewey Fault or at any of the oil and gas test wells. Therefore, a Corrective Action Plan is not required before injection into the Class V injection wells can be authorized.

5.0 INFORMATION TO SUBMIT TO RECEIVE AUTHORIZATION TO COMMENCE INJECTION

The Area Permit prohibits Injection into any deep Class V disposal well until a written Authorization to Commence Injection (ATCI) is issued by the EPA. Part II of the Area Permit contains requirements designed to verify that the proposed injection activities will not endanger USDWs. Part II of the Area Permit requires Powertech to collect the following information for each injection well and compile it into an Injection Authorization Data Package Report. A separate Injection Authorization Data Package Report shall be prepared for each deep injection well.

Each Injection Authorization Data Package Report will be reviewed by the EPA. If the information verifies that USDWs can be protected during the proposed injection activities, the EPA will issue a written ATCI.

5.1 Collection of Drill Core in the Injection Zone and Confining Zones

Part II, Section B of the Class V Area Permit requires Powertech to collect drill core from the Minnelusa injection zone and overlying confining zone formation during the drilling of each Class V injection well. The Class V Area Permit requires Powertech to collect drill core from the Lower Minnelusa confining zone while drilling the Madison water supply wells, if they are approved by the South Dakota Water Rights Program, **or** from DW No. 1 if it is drilled to the base of the Deadwood Formation, as Powertech proposed in the Class V Permit Application. The formations from which drill core is to be collected are listed in Table 10. Table 10 also includes the reasons for each type of formation test. The effective porosity and the permeability of the injection zone formationare used in the diffusivity equation for calculating the decline of injection-induced pressure in the injection zone with distance away from the injection well shown in Tables A-3 and A-4 of the Class V Permit Application. Determining the permeability and hydraulic conductivity of the confining zones verifies that they act as a hydrologic barrier to prevent flow the injection zone fluids out of the injection zone and protect USDWs. The permeability and hydraulic conductivity values the EPA will consider adequate are on the scale of those found in Table 8.2 of the Class III Permit Application and included in Table 11 below. Greene, 1993, determined that the vertical hydraulic conductivity of the Lower Minnelusa confining zone in two test wells near Rapid City. The vertical hydraulic conductivity in test well #1 was 0.3 ft/day, which converts to 1.14×10^{-7} cm/s. The vertical hydraulic conductivity in test well #2 was 9.3×10^{-3} ft/day, which converts to 3.6×10^{-9} cm/s.

Table 10. Drill Core Collection for Laboratory Testing

TYPE OF TEST	PURPOSE	DUE DATE
While drilling each Class V injection well, core samples shall be collected in the Minnelusa Porosity Zone injection zone	For laboratory testing to determine the porosity, effective porosity and permeability of the injection zone	Prior to receiving authorization to commence injection
While drilling each Class V injection well, core samples shall be collected in the Opeche Shale Confining Zone	To determine the porosity, permeability and hydraulic conductivity of the confining zones	Prior to receiving authorization to commence injection
While drilling the Madison water supply wells **or** DW No. 1, if drilled to the base of the Deadwood Formation, core shall be collected from the Lower Minnelusa confining zone.	To determine the porosity, permeability and hydraulic conductivity of the confining zones	Prior to receiving authorization to commence injection

Table 11. Permeability and Hydraulic Conductivity Values Expected for Confining Zone Formations (from Permit Application Table 8.2)

Formation/Area	Air Intrinsic Permeability (milliDarcys)	Water Hydraulic Conductivity (cm/s)
Fuson Shale Burdock Area	0.015	1.1549E-08
Fuson Shale Dewey Area	0.008	6.1595E-09
Skull Creek Shale Dewey Area	0.007	5.3896E-09
Morrison Shale in the Burdock Area	0.043	3.3107E-08
Morrison Shale in the Burdock Area	0.012	9.2392E-09

5.2 Well Logging Requirements

Part II, Section C of the Class V Area Permit requires Powertech to perform logging operations on each injection well. Logs of the Minnelusa injection zone and Lower Minnelusa confining zone must be performed on the Madison water supply wells, if they are approved by the South Dakota Water Rights Program. The types of well logs required are listed in Tables 3, 4 and 5 of the Area Permit. The reasons for conducting these well logs include:

1) Defining the vertical extent of the injection zone and overlying and underlying confining zones to confirm that the injection zone is separated from USDWs by confining zones;
2) Verifying that well casing is adequately cemented to prevent the movement of formation fluids through the cement-filled annulus between the well casing and the borehole wall.

5.3 Formation Testing

5.3.1 Potentiometric Surface Testing and TDS Analysis of Aquifers including Injection Zone

As the drillhole for each injection well is advanced, Part II, Section D.2.b of the Area Permit requires Powertech to isolate each aquifer listed in Table 12 and measure the potentiometric surface. After that, a minimum of two (2) fluid samples will be collected from each aquifer to be analyzed for the other constituents listed in Table 13. A minimum of three (3) additional fluid samples shall be collected from the injection zone and analyzed for TDS only. Part II, Sections D.2.b and D.2.c and Part V, Sections D.1.b and D.1.c of the Class V Area Permit includes sampling requirements to ensure that representative samples are collected from each aquifer. Part II, Section D.2.a of the Class V Area Permit requires the use of a tracer in the drilling mud that can be detected in groundwater samples using a field test, so Powertech can determine during the sampling process if a groundwater sample is contaminated by drilling mud. The Class V Area Permit requires that the potentiometric surfaces of the Minnelusa injection zone and the Madison aquifer be measured in DW No. 1, if it is drilled to the base of the Deadwood Formation, ***and*** in the Madison water supply wells, if they are approved by the South Dakota Water Rights Program. A minimum of two fluids samples must be collected from these wells in the Minnelusa injection zone and the Madison aquifer to be analyzed for the constituents in Table 12.

Table 12. Aquifers to be Isolated and Tested in Each Well Drillhole

Well Drillhole	Aquifers to be Tested
DW No. 1	Fall River Chilson Unkpapa/Sundance Minnekahta Limestone Minnelusa porosity zone
DW No. 3	Fall River Chilson Unkpapa/Sundance Minnekahta Limestone Minnelusa porosity zone
DW No. 1, if it is drilled to the base of the Deadwood Formation **and** the Madison water supply wells, if they are approved by the South Dakota Water Rights Program.	Minnelusa aquifer Madison aquifer

In the case of the Minnekahta Formation, if the potentiometric surface is not above the elevation of the formation top, Powertech is not required to collect any fluid samples from the Minnekahta Formation. If the potentiometric surface of the Minnekahta aquifer fluid is above the top elevation of the formation, then Powertech shall collect aquifer fluid samples to analyze for TDS and the other constituents in Table 12. If the Minnekahta Formation is not able to sustain pumping rates necessary for representative aquifer fluid samples to be collected, then Powertech shall document sampling efforts, but is not required to collect fluids samples from the Minnekahta Formation.

5.3.2 Demonstration that the Injection Zone Is Not a USDW

USDW means an aquifer or its portion:

(a)(1) Which supplies any public water system; or

(2) Which contains a sufficient quantity of ground water to supply a public water system; and

(i) Currently supplies drinking water for human consumption; or

(ii) Contains fewer than 10,000 mg/L TDS.

(b) Which is not an exempted aquifer.

There are no wells completed in the Minnelusa Formation being used to provide drinking water for human consumption within the Dewey-Burdock Project Area and Area of Review. If the TDS analyses of injection zone fluids are less than 10,000 mg/L, the injection zone is a USDW. This permit does not authorize injection into a USDW. If Powertech decides to pursue the use of the USDW as an injection zone, then a major modification of the Area Permit will be required. A major permit modification per 40 CFR § 144.39 and 40 CFR § 124.5 involves issuing a new draft permit and opening a public review process for the modifications.

5.3.3 Aquifer Characterization

The Class V Area Permit requires the collection of a minimum of two (2) formation fluid samples from each aquifer including the injection zone and the Madison aquifer to be analyzed for the parameters listed in Table 13. The Minnelusa fluid samples must be collected from DW No. 1 and DW No. 3. Fluid samples from the Madison Formation must be collected from the Madison water supply wells for comparison **and** from DW No. 1, if it is drilled to the base of the Deadwood Formation. The proposed locations of the Madison water supply wells relative to the Class V injection wells are shown in Figures 4a and 4b. Differences in water quality data between the aquifers will be used in evaluating the effectiveness of confining zones in separating the injection zone from the Madison Formation aquifer.

Table 13. Constituents to be Analyzed in Each Aquifer Including the Injection Zone and Madison Aquifer

Analytes
1. Alkalinity (Total)
2. Arsenic
3. Barium
4. Bicarbonate
5. Cadmium
6. Calcium
7. Carbonate
8. Chloride
9. Chromium
10. Conductivity
11. Fluoride
12. Lead
13. Lead-210
14. Magnesium
15. Mercury
16. pH
17. Potassium
18. Radium-226
19. Radium-228
20. Selenium
21. Silver
22. Sodium
23. Specific Gravity
24. Strontium
25. Sulfate
26. Thorium-230
27. TDS
28. TSS
29. Uranium (Total)
30. Uranium (Natural)

5.3.4 Formation Testing Involving Injection

5.3.4.1 Limited Authorization to Inject

The formation tests listed in Table 14 involve injection activity. Powertech must obtain a limited authorization to inject from the EPA before injection for testing purposes can occur. The limited authorization to inject only authorizes injection for the purpose of conducting the specified tests. This limited authorization to inject will be issued only under the following conditions:

1) Powertech has demonstrated the injection zone is not a USDW,
2) The injection zone top and bottom have b een identified from well logging results, and
3) The top perforation of the well is within the injection zone and at least 50 feet below the lowest USDW at the well site.

Part II, Section I of the Class V Area Permit provides more specific information about how the EPA will review the Injection Authorization Data Packages and how the EPA will make a decision on issuing a Limited Authorization to Inject for testing purposes.

The Limited Authorization to Inject will have the following conditions:

1) The EPA will specify a Maximum Allowable Injection Pressure (MAIP) for this limited authorization to inject calculated according to the equation in Section 7.4 of this document,
2) The specific gravity of the test injectate shall be no higher than 1.0113 (the specific gravity permit limit discussed in Section 7.5), and
3) The test injectate meets the injectate permit requirements in Section 7.8, Tables 19 and 20.

Table 14. Formation Testing Involving Injection

TYPE OF TEST	PURPOSE	DUE DATE
Step Rate Test	Initial test to determine site specific fracture pressure to use for calculating the MAIP permit limit for each well. Monitor injection pressures at surface and bottom hole to determine the actual injection zone parting pressure and the injection pressure measured at the surface at the point the injection zone parting pressure is reached.	After receiving authorization to inject for testing purposes, but prior to receiving authorization to commence injection
Initial Radioactive Tracer Survey	Baseline assessment of ability of the cement behind the longstring casing to prevent movement of injected fluids out of the approved injection zone.	After receiving authorization to inject for testing purposes and MAIP has been determined from the Step Rate Test, but prior to receiving authorization to commence injection

5.3.4.2 Determining Site-specific Fracture Pressure

Part II, Section J.4.a of the Area Permit requires Powertech to run a Step Rate Test on the injection zone for each well to determine the site-specific fracture pressure of each injection zone and fracture gradient at each injection well site. The fracture pressure is the pressure at which injected fluid creates new fractures in the injection zone formation or propagates existing fractures g in the injection zone. The fracture pressure increases with depth because the pressure from the weight of overburden strata acts to resist fracturing of the geologic unit. The amount of change in fracture pressure with depth is the fracture gradient

A Step Rate Test is conducted by injecting a fluid into the formation at a series of increasing pumping rates. The Area Permit requires the use of pressure sensors located within the injection zone and at the wellhead during the Step Rate Test. At each step, the injection pumping rate is increased an incremental amount. That rate is held for a period of time to allow pressure conditions in the injection zone to stabilize. The stabilized injection zone pressure for each rate is recorded. The stabilized injection zone pressures at each injection rate step are plotted on a graph as shown in Figure 10.

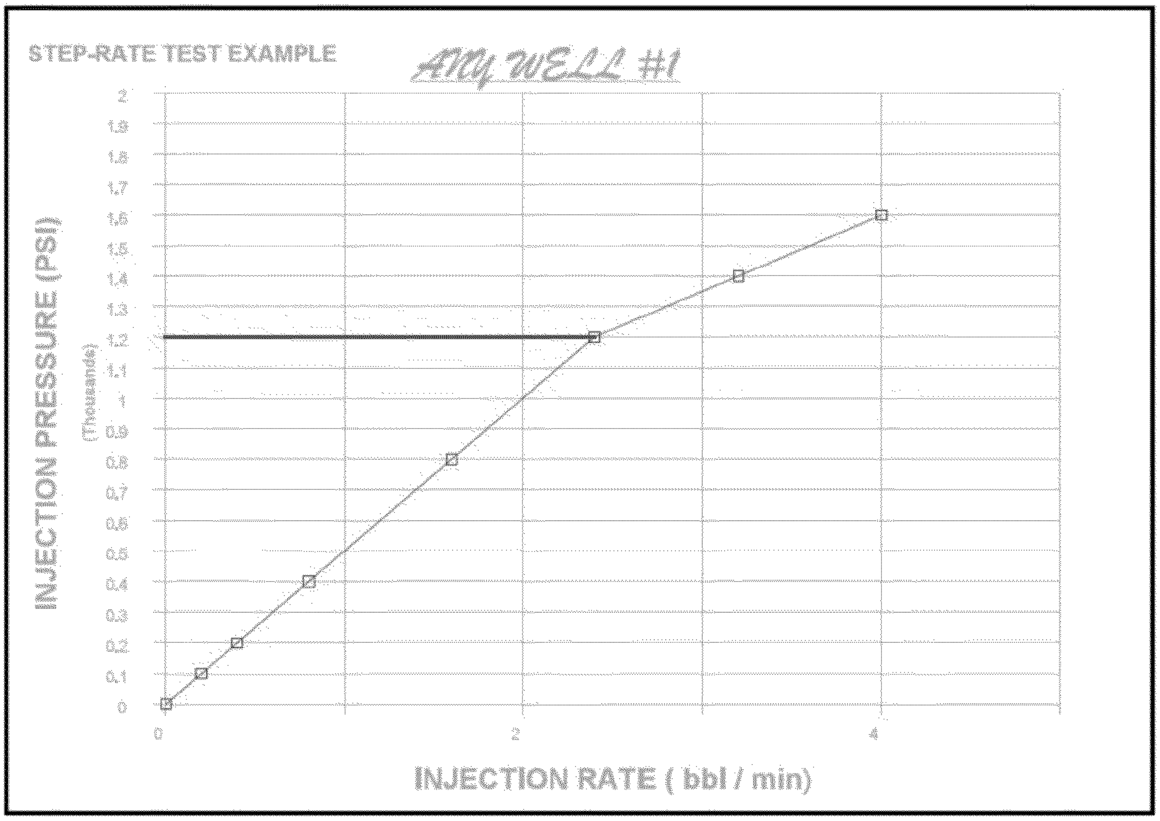


Figure 10. Step Rate Test Graph of Injection Rate versus Stabilized Injection Zone Pressure.

The slope of a best fit line through the data points should be constant as long as the injection zone fracture pressure is not exceeded. Once fractures begin forming within the injection zone, the slope of the line changes. The fracture pressure is identified as the point at which the slope of the plotted line of injection pressure versus injection rate changes. In Figure 10 the injection zone fracture pressure is identified as 1,200 psi.
The procedure for conducting the Step-Rate Test is found at the EPA Region 8 UIC website: https://www.epa.gov/uic/uic-epa-region-8.

The fracture gradient is calculated from the measured injection zone fracture pressure using the formula below. After the fracture pressure for each injection formation has been determined from the Step Rate Test conducted on each injection well, this value will be used in the equation below along with the depth to the pressure sensor located in the injection zone.

The relationship between the fracture pressure measured down-hole at the injection zone level, fracture gradient and the depth to the injection zone pressure sensor is expressed by the following formula:

$$fg = FP/d$$

FP = formation fracture pressure (from Step Rate Test results)
fg = fracture gradient (calculated)
d = depth to the injection zone sensor

The difference between the fracture pressure measured at the injection zone and the fracture pressure measured at the wellhead is the pressure induced on the injection zone from the weight of the column of injectate within the injection tubing. There may also be a loss in pressure at the injection zone due to friction between the Injectate and the tubing. The Area Permit allows the loss in pressure due to friction to be added back to the MAIP after the MAIP is determined as described in Section 7.4.

5.4. Injection Zone Pressure Calculations

5.4.1 Critical Pressure Rise Calculations in the Injection Zone

As discussed above, the injection zone top and bottom elevations will be identified for each injection well based on drillhole logs and the potentiometric surface elevations will be determined for the Unkpapa/Sundance, Minnelusa injection zone and the Madison aquifers. Part II, Section E.5.b.1 of the Class V Area Permit requires Powertech to develop a model to estimate expected drawdown of the Madison aquifer potentiometric surface at each of the Madison water supply well locations. This site specific information is required to calculate the actual critical pressure rise for each injection zone as discussed in Section 4.4.1. Part II, Section F.1 of the Area Permit requires Powertech to recalculate the critical pressure rise that will move Minnelusa injection zone fluid upward into the overlying Unkpapa/Sundance and downward into the underlying Madison USDWs at DW No.1 and DW No. 3.

5.4.2 Injection-Induced Injection Zone Pressure Calculations

Part II, Section F.2 of the Area Permit also requires Powertech to recalculate the injection zone formation pressures resulting from 12 years of injection activity, a 116 gpm flow rate and site-specific data and compare the extent of the pressure with distance away from the injection well with the critical pressures calculated as discussed in 5.4.1 above. Powertech will use this information to demonstrate that each injection well is located a sufficient distance away from abandoned oil and gas test wells and the Dewey Fault to prevent the movement of fluids out of the injection zone into USDWs.

5.4.3 Calculation of Maximum Injection Rate for Each Class V Injection Well

After calculating critical pressure rise for each injection zone and the injection-induced injection zone pressure according to distance from each injection well using the injection rate needed to dispose of the maximum anticipated volume of treated ISR waste fluids and 12 years of injection activity, Part II, Section F.3 of the Area Permit requires Powertech to calculate a maximum injection rate for each injection well. The maximum injection rate must be determined such that the critical pressure in each injection zone is not exceeded 1,000 feet away from the nearest potential breech in confining zones. This maximum injection rate shall ensure that no injection zone fluids move out of the injection zone through a pathway through the confining zones. Powertech shall include the maximum injection rates for each Class V in the Injection Authorization Data Package Report to be reviewed by the EPA to determine the maximum injection rate permit limit for each injection well. The maximum injection rate permit limits set by the EPA will be included in the Authorization to Commence Injection document.

If Powertech constructs additional Class V injection wells that will be injecting into the Minnelusa injection zone in either the Dewey Area or the Burdock Area, the maximum injection rate for each injection well shall be calculated taking into account the pressure effects of having more than one injection well in these areas, as applicable.

5.5 Initial Demonstration of Mechanical Integrity

Before receiving the ATCI, the Powertech must demonstrate that each injection well has both internal and external mechanical integrity. To demonstrate internal mechanical integrity, the test must show that there is no leakage through the well casing and tubing. To demonstrate external mechanical integrity the procedure must show the cement between the well casing and the borehole wall will prevent fluid movement across the confining zones.

5.5.1 Internal Mechanical Integrity: Tubing -Casing-Annulus (TCA) Pressure Mechanical Integrity Test Procedure

Part III, Section G of the Class V Area Permit requires the annulus between the well casing and injection tubing to be filled with a fluid. Part IV, Section K of the Class V Area permit requires that an induced pressure is maintained on the annulus fluid at all times and that induced pressure must always be at least 100 psi above the injection pressure. Part V, Section D.3, Table 17A includes the requirement that the TCA pressure is continuously monitored.

The internal mechanical integrity test involves stabilizing the TCA pressure and temperature, recording the TCA pressure for one hour. Successful demonstration of internal mechanical integrity requires less than 10 percent pressure fluctuation measured over the hour.

5.5.2 External Mechanical Integrity

The initial demonstration of external mechanical integrity will be a cement bond log of the surface casing and the longstring casing of each injection wellrequired under Part II, Section C (Tables 3 and 5). The cement bond log, required under Part II, Section C, must demonstrate 80% bonding through the confinement zones as required under Part II, Section H.3 and Part II, Section I.1.f.

Part II, SectionJ.5 of the Class V Area Permit also requires an initial radioactive tracer test. The purpose is to conduct a baseline assessment of ability of the cement behind the longstring casing to prevent movement of injected fluids out of the approved injection formations. After receiving authorization to inject for testing purposes and a MAIP has been determined from the Step Rate Test information, Powertech must conducta radioactive tracer test while injecting below the injection zone fracture pressure but not below the MAIP.

Part II, Section J, Table 10 and Section J.5 requires an initial Temperature Survey Log to provide a baseline temperature profile of formations along the well bore that will be used for comparison of results from future Temperature Survey Logs required under Part V, Section C.6.c, Table 13 or ongoing demonstration of e xternal mechanical integrity. The initial Temperature Survey Log will not be useful for providing an initial demonstration of external mechanical integrity because, by the time the Temperature Survey Log will be conducted, no injection will have taken place to introduce fluids of lower temperature that could move up along any pathways through the cemented annulus between the well casing and the borehole. Once injection commences, future Temperature Survey Logs will be used to identify any leaks through the cement between the well casing and borehole as a temperature drop detected by the Temperature Survey Log would signify a change from the pre-injection baseline conditions.

5.6 The EPA Review of Well Logging and Testing Results

The results of all the tests and logs performed prior to the Authorization to Commence Injection will be submitted to the EPA for evaluation. Each item is described in Table 15 with an outcome if results are not as expected.

Table 15. Purpose of Required Well Logs/Tests and Resulting Outcomes

Log or Test Results	Purpose	Outcome
Presence and thickness of confining zones for the injection zone shown in well logs from each well.	Document the presence and thickness of confining zones for hydrologic isolation of the injection zone from USDWs.	Demonstration to the EPA that confining zones are present to protect USDWs. If no confining zones are present, an ATCI will not be issued.
Potentiometric surfaces measured for each aquifer intersected at each Class V well location and Minnelusa and Madison potentiometric surface measured at the DW No. 1 well, if it is drilled to the base of the Deadwood Formation, **and** the Madison water supply wells, if they are approved by the South Dakota Water Rights Program.	Differences in aquifer potentiometric surfaces demonstrate confining zones are present and provide hydrologic isolation of the injection zone from USDWs.	The Minnelusa and Madison aquifers are expected to have different potentiometric surfaces. However, if they do not, this alone does not indicate the confining zone is not adequate.
Differences in water quality for the Minnelusa and Madison at the DW No. 1 well, if it is drilled to the base of the Deadwood Formation, **and** the Madison water supply wells, if they are approved by the South Dakota Water Rights Program.	To further verify that confining zones are present and provide hydrologic isolation of the injection zone from USDWs.	A difference in water quality parameters as discussed under the Section 3.3.3 on Additional Hydrologic Evaluation of the Lower Minnelusa Confining Zone demonstrates the confining zones prevent mixing of the aquifer fluids.
Calculations of critical pressure and injection-induced pressure in each injection zone to evaluate the distance away from each injection well the injection zone pressure is greater than or equal to the critical pressure rise that would cause injection zone fluids to move out of the injection zone along a hypothetical pathway through the confining zones.	To demonstrate that each injection well is located a sufficient distance away from abandoned oil and gas test wells and the Dewey Fault to prevent the movement of fluids out of the injection zone into USDWs.	If the injection well location is located far enough away from a feature that is a potential pathway through the confining zones, the ATCI may be issued. Powertech must also calculate a maximum injection rate that will assure the injection zone calculated critical pressure is not exceeded 1000 feet from pathways through the confining zones.
The vertical extent of the injection zone at each injection well location and location of well perforations within the approved injection zone. The depth of the base of the lowermost USDW intersected by the well bore.	To document that the injection zone top and bottom are known and the well perforations are placed within the injection zone. The top well perforation must be 50 feet below the base of the lowermost USDW intersected by the well bore.	The perforations must be located within the injection zone for ATCI to be issued. If it turns out any perforations are outside of the injection zone, they have to be closed off before ATCI is issued. If the top perforation is not less than 50 feet below the base of the lowermost USDW intersected by the

		well bore, it must be closed before the ATCI will be issued.
TDS concentrations for each injection zone.	Verification that an injection zone is a not a USDW.	The ATCI may be issued for a well only if Powertech demonstrates the injection zone is not a USDW.
Step Rate Test data	Provides injection zone fracture pressure for calculation of fracture gradient at each injection well location so the permit limit for MAIP can be calculated for each injection well.	The ATCI may be issued for a well only if the MAIP permit limit has been established from a Step Rate Test, site-specific calculated fracture pressure and site specific injection depth information.
Initial demonstration of mechanical integrity	To demonstrate that well construction prevents the movement of injectate and injection zone fluids into USDWs through the well tubing and casing and through the cemented annulus between the outer well casing and the borehole wall.	The ATCI may be issued for a well only after both internal and external mechanical integrity havebeen demonstrated for the injection well.

The EPA will issue a written ACTI document only upon finding that Powertech achieved the purpose of each test and meets the outcomes described above. The ATCI will contain the MAIP permit limit and the maximum injection rate permit limit based on site-specific information as described in Part II, Section J.4.c and Part II, Section F.3 of the Class V Area Permit.

6.0 WELL CONSTRUCTION REQUIRMENTS

The approved well construction plans are included in Part III of the Class V Area Permit and will be binding on Powertech. Changes in construction plans during construction may be approved by the EPA as minor modifications per 40 CFR § 144.41. No such changes may be physically incorporated into construction of the well prior to approval of the modification by the EPA in accordance with 40 CFR § 144.52(a)(1). In the Class V Permit Application, Powertech originally proposed drilling all the way down to the Precambrian basement during the construction of DW No. 1 in order to collect information on the Deadwood Formation aquifer fluids to determine if it would be an effective injection zone. Because the EPA is not proposing authorization of the Deadwood injection zone wells, Powertech may decide not to drill down to the Precambrian basement during the construction of DW No. 1. The Class V Area Permit contains two proposed construction plans for the DW No. 1: the first plan accommodates well construction in the hole drilled down to Precambrian basement; the second plan resembles the plan for DW No. 3 to accommodate the well construction in a hole that will not be drilled below the Lower Minnelusa confining zone. If Powertech decides not to drill the hole for DW No. 1 down to the Precambrian basement, then the construction plan for DW No. 1 will be similar to that of DW No. 3. The construction diagrams for wells DW No. 1 with drillhole total depth at the Precambrian basement and drillhole total depth in the Minnelusa Formation and DW No. 3 are included in Figures 3, 4 and 5, respectively, of the Area Permit.

If Powertech decides to drill the hole for DW No. 1 to Precambrian basement, each aquifer encountered must be isolated within the drillhole and fluid samples of all aquifers encountered will be collected and analyzed for TDS and the other constituents in Table 13. The potentiometric surface will be measured for each aquifer encountered. Logs will be run in the drillhole to gather information about the proposed injection zoneand confining zones. Core samples must be collected through the injection zone and confining zones for porosity and permeability testing. Then the hole will be plugged back approximately to the base of the Minnelusa injection zone and the well will be completed as a Minnelusa injection well as shown in Figure 3 of the Area Permit. Well DW No. 3 will be drilled, tested and logged in a similar manner, except the drillhole will not extend below the Lower Minnelusa confining zone.

Based on the stratigraphic Log of the Minnelusa Formation from the Earl Darrow #1 Oil and Gas Exploration Well included as Appendix A, it appears that there may be sandstone with porosity lower than the depth proposed for the Minnelusa Porosity Zone. During the drilling of both DW No. 1 and DW No. 3, the Class V Area Permit allows Powertech to drill deeper into Minnelusa Formation to examine these lower sandstones for porosity and suitability for injection. The hole may be plugged back to a shallower depth as needed if the lower sandstones do not have enough porosity to be included in the injection zone.

6.1 Casing and Cementing (40 CFR § 147.2104 (d))

UIC regulations and the Area Permit require the well casing and cement used in the construction of all wells, including deep Class V injection wells to protect USDWs by:

1. Having the surface casing set 50 feet below the lowermost USDW;
2. Cementing surface casing by recirculating the cement to the surface from a point 50 feet below the lowermost USDW; or
3. Isolating all USDWs by placing cement between the outermost casing and the well bore, and
4. Isolate any injection zone by placing sufficient cement to fill the calculated space between the casing and the well bore to a point 250 feet above the injection zone; and
5. Use cement:
   (i) Of sufficient quantity and quality to withstand the maximum operating pressure; and
   (ii) Which is resistant to deterioration from formation and injection fluids; and
   (iii) In a quantity no less than 120% of the calculated volume necessary to cement off a zone.

The Area Permit requires that well construction does not result in the movement of fluids into USDWs. All USDWs intersected by each injection well will be isolated by placing cement between the outermost casing and the well bore. The injection zone will be isolated by placing sufficient cement to fill the calculated space between the casing and the well bore to meet the following specifications:

1. For DW No. 1 longstring casing cement from the base of the Minnelusa Formation to the surface for construction in the drillhole down to Precambrian basement.
2. For DW No. 3 and DW No. 1 constructed in a drillhole no deeper than the Lower Minnelusa confining zone, longstring casing cement from approximately 200 to 250 feet below the base of the Minnelusa Porosity Zone injection zone to the surface.

A summary of cementing and casing information for the four proposed injection wells is included in Table 16.

Remedial cementing may be required if the casing cement is shown to be inadequate by cement bond log or other demonstration of external mechanical integrity.

Table 16. Well Casing and Cement Summary

	Burdock		Dewey
	DW No.1 (Figure 3 in Permit)	DW No.1 alternate (Figure 4 in Permit)	DW No.3 (Figure 5 in Permit)
Conductor Casing (in)	13 3/8"	13 3/8"	13 3/8"
Depth (ft)	60'	60'	60'
Surface Hole (in)	12 1/4"	12 1/4"	12 1/4"
Depth (ft)	Top of Minnelusa (~1,615')	50' below base of Sundance aquifer (~1,615')	50' below base of Sundance aquifer (~1,305')
Surface Casing (in)	9 5/8"	9 5/8"	9 5/8"
Cement Interval (ft)	From top of Minnelusa to surface (0' - ~1,615')	From 50' below base of Sundance aquifer to surface (0 - ~1,615')	From 50' below base of Sundance aquifer to surface (0 - ~1,305')
Longstring Hole (in)	8 1/2"	8 1/2"	8 1/2"
Depth (ft)	Near base of Minnelusa (~2,765')	Up to ~250' below base of Minnelusa Porosity injection zone (~2,455')	Up to ~250' below base of Minnelusa Porosity injection zone (~2,790')
Longstring Casing (in)	7"	5 1/2"	5 1/2"
Cement volume	120% of calculated volume between exterior of casing and surrounding annulus.	120% of calculated volume between exterior of casing and surrounding annulus.	120% of calculated volume between exterior of casing and surrounding annulus.
Cement Interval (ft)	From base of Minnelusa to surface (0' - < ~2,765')	Up to ~250' below base of Minnelusa Porosity injection zone to surface (0' - ~2,455')	From ~250' below base of Minnelusa Porosity injection zone to surface (0' - ~2,790')
Open Hole (ft)	6 1/4"	n/a	n/a
Total Depth (ft)	At Precambrian basement (~3,195')	Up to 250' below base of Minnelusa Porosity injection zone (~2,455')	Up to 250' below base of Minnelusa Porosity injection zone (~2,790')

The Class V Area Permit requires the use of a float shoe with a float collar one or two joints up from the bottom and that centralizers will be placed a minimum of one every fifth joint. The use of floating equipment is standard industry practice during the drilling of deep wells.[14]

[14] See e.g., http://www.halliburton.com/en-US/ps/cementing/casing-equipment/floating-equipment/default.page?node-id=hfqela4z

6.2 Tubing and Packer

Under Part III, Section F, injection tubing is required to be installed from a packer up to the surface inside the well production casing. The packer shall be set no more than 100 feet above the uppermost perforation. The tubing and packer are designed to prevent injection fluid from coming into contact with the outermost casing.

6.3 Tubing-Casing Annulus (TCA)

As discussed in Section 5.5.1, Part III, Section F of the Class V Area permit requires that the TCA will be filled with fresh water treated with a corrosion inhibitor or other fluid additives determined by Powertech. Part IV, Section L of the Class V Area permit requires that an induced pressure is maintained on the annulus fluid at all times and that a pressure be applied continuously on the fluid within the TCA. The TCA pressure must be continuously monitored which provides for detection of leaks in the injection tubing, packer or longstring casing. Periodic recording of TCA pressure will serve as the pressure test for the casing, tubing and packer in order to demonstrate internal mechanical integrity.

6.4 Monitoring Devices

Powertech will be required to install and maintain wellhead equipment that allows for continuous monitoring of injection pressure, flow rate, cumulative volume, and TCA pressures and providing access for sampling the injected fluid. Monitoring requirements are discussed later under Section 8.0.

6.5 Protective Automated Monitoring and Shut-off Devices

Part III, Section H, of the Area Permit requires the installation of an automated control system with control switches to alarm the operator in the event that any of the Area Permit conditions related to minimum or maximum permit limits are met. The system must be set up to cease injection operations until the operator identifies and corrects the problem. For example, a high injection pressure switch (set just below the MAIP set in the Area Permit for each well) and a low annulus differential pressure switch (set just above limit in the Area Permit for each well) will shut off injection pump power and alarm the operator so that the well can be fully isolated and secured. Protective automated monitoring requirements are discussed under Section 8.1.5.

7.0. WELL OPERATION REQUIREMENTS

The Area Permit prohibits injection between the outermost casing protecting USDWs and the well bore per 40 CFR § 146.12(a)(2). The Area Permit also prohibits injection until all requirements to obtain the Authorization to Commence Injection have been met and the EPA has issued written approval for injection to commence.

7.1 Mechanical Integrity

Under Part IV of the Class V Area Permit, injecting into a well that lacks mechanical integrity is prohibited under UIC regulations. The Area Permit requires that each injection well maintains mechanical integrity at all times. An injection well has mechanical integrity if:

1. There is no significant leak in the casing, tubing, or packer (Internal Mechanical Integrity); and
2. There is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore (External Mechanical Integrity).

7.2 Prohibition on Injection if Injection Zone is a USDW

Part IV, Section B of the Area Permit does not allow Powertech to construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of fluid containing any contaminant into a USDW. The Area Permit authorizes injection into only a non-USDW. As discussed in Section 5.3.2, Powertech must demonstrate that the Minnelusa injection zone is not a UDSW. While the aquifers are not currently being used as a source of drinking water for human consumption, if TDS analytical results for a proposed injection zone are below 10,000 mg/L, it would fall under the definition of a USDW, and Powertech would be prohibited from injecting under this permit. If Powertech wanted to pursue injection, a major modification of the Area Permitwould be required under 40 CFR §§ 144.39 and 124.5. A new public review process would be initiated involving a public comment period and the opportunity to request a public hearing. Only the modifications to the Area Permit would be open for public review.

7.3 Approved Injection Zone and Perforations

Part IV, Section F of the Area Permit does not allow perforation of an injection well until after:

- All logs and tests have been performed to identify the depths of the injection zone and confining zones, and
- The logs and tests have been analyzed by a knowledgeable log analyst to correctly identify the extent of the injection zone for each well.

The Area Permit will authorize injection allowed only within the approved injection zone depths based on well drillhole logs and only after the EPA has issued a written Authorization to Commence Injection. Approximate depths to each injection zone is shown in Table 1 of this Area Permit. The site-specific depth to each injection zone for each well under the Area Permit will be established by the well logging discussed under Section 5.2 of this document. Accordingly, the approved top of each injection zone must be 50 feet or more belowthe base of the lowest USDW intersected by the well bore. The Authorization to Commence Injection will include the actual top and bottom depths of the approved injection intervals based on well drillhole logs.

Powertech may install additional perforations of the well bore within the injection zone, provided all perforations remain within the approved injection zone and no perforation is higher than theperforation used to calculate the MAIP. During construction Powertech may make changes to the well construction design, but must provide notice to the EPA in accordance with Part III, Section C.1 of the Class V Area Permit and receive approval through a minor permit modification before any changes are implemented. After well construction is complete, changes to well construction, including the addition of perforations, can be made only through a major permit modification under 40 CFR §§ 144.39 and 124.5 as stated in Part III, Section C.2 of the Class V Area Permit. This action would invoke a new public review process involving a public comment period and the opportunity to request a public hearing. Only the modifications to the Area Permit would be open for public review.

7.4 Injection Pressure Limit

As required under 40 CFR § 146.12(a)(1), the Area Permit requires that, except during stimulation, injection pressure at the wellhead shall not exceed a maximum which shall be calculated so as to assure that the pressure in the injection zone during injection does not initiate new fractures or propagate existing fractures in the injection zone. The Area Permit also stipulates that in no case shall injection pressure cause the movement of injection or formation fluids into an underground source of drinking water.

The Area Permit requires that Powertech calculate the injection zone fracture pressure measured at the surface and that the MAIP be set at 90% of the injection zone fracture pressure. This assures a conservative MAIP with a 10% safety factor. The injection zone fracture pressure must be calculated as discussed previously in Section 5.3.4.2 in the context of determining the site-specific fracture gradient using the fracture pressure measured in the injection zone during a Step Rate Test that will be performed on each Class V injection well.

To determine MAIP, a second calculation is performed to determine the fracture pressure measured at the wellhead during the injection of the approved Injectate. The equation below will be used to calculate the fracture pressure measured at the wellhead taking into account the pressure induced on the injection zone by the weight of the injectate in the injection tubing.

$$FP = [fg - (0.433 * sg)] * d$$

FP = fracture pressure measured at the wellhead (calculated value)
fg = fracture gradient (calculated from Step Rate Test results)
sg = injectate specific gravity permit limit
d = depth to top well perforation

The equation input parameters will be as follows:

- The specific gravity value used is the permit limit value for specific gravity, which the permit sets at 1.0113;
- The fracture gradient used will be the value calculated as discussed under Section 5.3.4.2;
- The depth to the top well perforation will be determined from well construction information for each Class V injection well. Each injection well will be constructed so the top perforation, through which injectate will enter the injection zone from the injection well, is located within the injection zone formation.

Once this fracture pressure is calculated for each Class V well injection zone, the EPA will set the MAIP at 90% of the calculated fracture pressure. As discussed in Section 5.3.4.2, Powertech may add the pressure loss due to friction between the Injectate and the injection tubing to the MAIP as stipulated in Part. II, Section J.4.d.

Table 17 provides estimates of MAIP values for each injection well. A fracture gradient of 0.68 psi/foot was used to calculate the fracture pressures in Table 17. This value was taken from Powertech's Class V Permit Application and is based on a value used by Wyoming Enhanced Oil Recove ry Institute (EORI). The EORI is an applied-research entity associated with the University of Wyoming, School of Energy Resources. EORI was created and is financially supported by the Wyoming State Legislature to help the State of Wyoming and its energy producers recover a large resource of stranded oil in depleted oil reservoirs. One of EORI's areas of focus is the generation, compilation and analysis of Wyoming oilfield data. The fracture gradient value of 0.68 psi/foot is conservative because it is lower than fracture gradient values derived from site specific studies performed within Wyoming oil fields. The stratigraphy at the Dewey-Burdock is similar to the stratigraphy in Wyoming oil fields, so it is appropriate to use this value in the calculations at the Dewey-Burdock Project Area. The Step Rate Test performed on each Class V injection well will provide the actual site-specific data that will be used to determine the site specific fracture pressure from which fracture gradient will be calculated for each injection well as discussed in Section 5.3.4.2.

The fracture pressure calculation discussed above was used to determine the approximate fracture pressure of each proposed injection zone using the fracture gradient and depths provided in the Class V Permit Application and the specific gravity permit limit of 1.0113. The calculated MAIP in Table 17 is 90% of the calculated fracture pressure. The permit limit MAIP for each injection zone will be 90% of the calculated fracture pressure based on site specific parameters.

Table 17. MAIP Estimates for the Minnelusa Injection Zone at DW No. 1 and DW No. 3.

Formation Name	Depth Used to Calculate Fracture Pressure (feet)	Fracture Gradient (psi/feet)	Calculated Fracture Pressure (psi)	Calculated MAIP (90% Calculated Fracture Pressure) (psig)
Minnelusa (Burdock)	1,615	0.68	390	351
Minnelusa (Dewey)	1,950	0.68	471	423

7.5 Injectate Specific Gravity Limit

As discussed in the previous section, the specific gravity of the injectate affects the injection pressure at the level of the injection zone. Because an increase in the specific gravity of the injectate results in an increase in injection pressure at the level of the injection zone, Part IV, Section G of the Area Permit establishes a maximum specific gravity to ensure that the pressure from injection within the injection zone remains below the fracture pressure. The Class V permit application estimated that the TDS of the injectate will be 15,000 mg/L. This TDS value is equivalent to a specific gravity of 1.0113[15]. The Area Permit sets the permit limit for specific gravity of 1.0113. Setting the permit limit at a higher specific gravity results in a lower calculated MAIP because the injectate column weight is adding a larger pressure component into the calculation. Setting a higher specific gravity permit limit creates a safety factor between the operating conditions and the fracture pressure of the injection zone formation in case there are violations of the specific gravity permit limit or the injection pressure permit limit.

7.6 Injection Volume

The Class V Area Permit does not set an injection volume limit. Cumulative injected fluid volume limits are set only when an aquifer exemption is being proposed to assure that injected fluids remain within the boundary of the aquifer exemption area within a USDW. The Minnelusa injection zone aquifer is not expected to be a USDW. The cumulative volume of injectate will be monitored continuously as required under Part V, Section D.3, Table 17A and will be calculated and reported to the EPA quarterly as required under Table 17D.

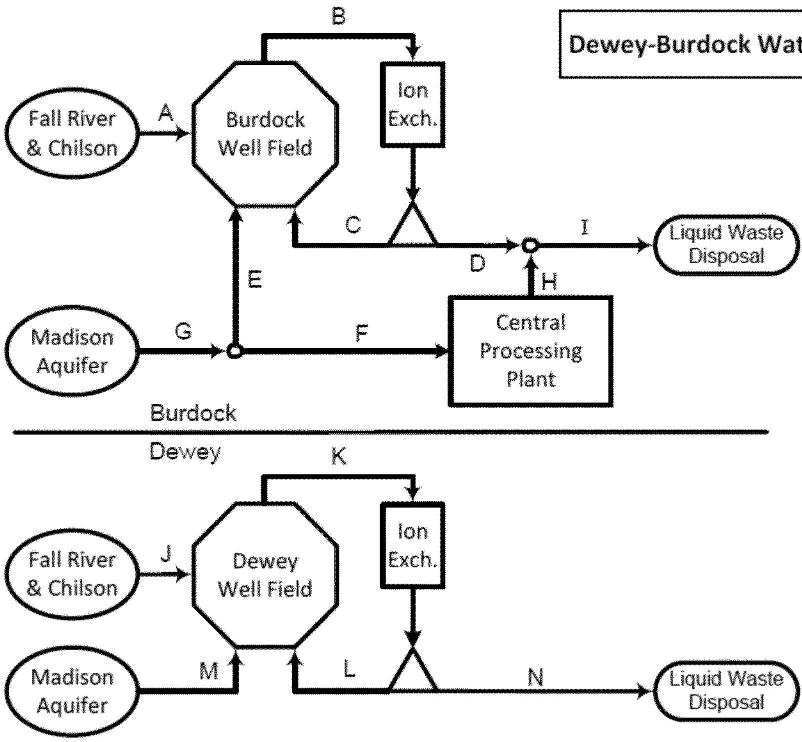
7.7 Injection Rate Requirements

7.7.1 Waste Fluid Flow Rate Based on Anticipated Project-Wide Flow Rates

Figure 11 shows the anticipated project-wide water balance flow rates for the Dewey-Burdock operation during uranium recovery and wellfield restoration. The maximum gross pumping rate from producing wellfields is currently set by NRC license conditions at a rate of 4,000 gpm. Powertech may eventually request a license amendment from the NRC to increase the maximum allowable gross pumping rate to 8,000 gpm to provide operational flexibility. The estimates of waste fluids flow rates discussed in this section are based on a maximum allowable gross pumping rate of 8,000 gpm.

[15] http://www.hamzasreef.com/Contents/Calculators/SalinityConversion.php

Dewey-Burdock Water Balance



Stream ID	Description
A	Burdock Aquifer Bleed
B	Burdock Extraction Composite
C	Burdock Reinjection
D	Burdock Well Field Bleed
E	Burdock Madison Make-up
F	Burdock Fresh Brine Make-up
G	Burdock Madison, Total
H	Burdock CPP Brine
I	Burdock Liquid Waste
J	Dewey Aquifer Bleed
K	Dewey Extraction Composite
L	Dewey Reinjection
M	Dewey Madison Make-up
N	Dewey Liquid Waste

Water Balance Flow Rates (gpm)											
Operation Phase	**Aquifer Bleed Options**	**Disposal Option**	**Burdock**								
			Stream ID								
			A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**
Recovery	0.875%	Deep Disposal Wells	42	4800	4758	42	0	12	12	12	54
		Land Application	42	4800	4758	42	0	12	12	12	54
Restoration	Without Groundwater Sweep	Deep Disposal Wells	2.5	250	175	75	73	0	73	0	75
		Land Application	2.5	250	0	250	247.5	0	247.5	0	250
	With Groundwater Sweep	Deep Disposal Wells	42	250	175	75	33	0	33	0	75
		Land Application	42	250	0	250	208	0	208	0	250

Water Balance Flow Rates (gpm)							
Operation Phase	**Aquifer Bleed Options**	**Disposal Option**	**Dewey**				
			Stream ID				
			J	**K**	**L**	**M**	**N**
Recovery	0.875%	Deep Disposal Wells	28	3200	3172	0	28
		Land Application	28	3200	3172	0	28
Restoration	Without Groundwater Sweep	Deep Disposal Wells	2.5	250	175	73	75
		Land Application	2.5	250	0	247.5	250
	With Groundwater Sweep	Deep Disposal Wells	42	250	175	33	75
		Land Application	42	250	0	208	250

Figure 11. Anticipated Project Wide Flow Ratesduring Uranium Recovery and Groundwater Restoration.

During uranium recovery, the aquifer bleed rate will be 42 gpm in the Burdock Area as shown in Figure 11, Column A and 28 gpm in the Dewey Area as shown in Column J, which is a total of 70 gpm of waste fluids produced by wellfield bleed. In addition, the Central Processing Plant in the Burdock Area will produce an estimated 12 gpm of waste fluids. During aquifer restoration, the Powertech estimates that the RO treatment process will produce a reject fluid waste stream that is 30% of the total volume of water treated. Based on a total groundwater extraction rate of 250 gpm from both the Dewey and Burdock Areas (Figure 11, Columns B and K), a 30% reject rate results in a total of 75 gpm of waste fluids from both the Dewey and Burdock Areas (Figure 11, Columns I and N, Deep Disposal Well rows, both with and without groundwater sweep).

Based on these estimates, the maximum rate of waste fluid generation during concurrent uranium recovery and wellfield restoration would be 232 gpm of waste fluids that will be routed to the deep injection wells. Without taking into account evaporation from the treatment and storage ponds, the deep disposal wells will need to have an injection capacity of 232 gpm. A waste fluid flow rate of 232 gpm will not be routed to the deep injection wells continuously throughout the project; this is the maximum flow rate anticipated during the life of the project.

Because there are only two Minnelusa injection zone wells proposed at this time and assuming the Class I wells may not be constructed, the average maximum injection rate that will be required at each well to dispose of the anticipated maximum volume of ISR waste fluid is 116 gpm. If this flow rate exceeds the maximum flow rates calculated as discussed in Section 4.4.2, Powertech will need to construct at least one additional Minnelusa injection well. Part II, Section F.4 requires Powertech to take into account the pressure effects of an addition al well injecting into the Minnelusa injection zone. If three wells are constructed, the maximum average injection rate for each well will decrease to 77.33 gpm. Part II, Section F.3 of the Class V Area Permit requires Powertech to calculate a maximum injection rate that will assure no injection zone fluids will move into a USDW due to injection-induced pressure in the injection zone as discussed in Section 4.4.2.

7.7.2 Injection Rate Permit Limits

As discussed in Section 4.4.2, the injection rate is an input value into the diffusivity equation used to calculate the distance from each injection well the injection-induced fluid pressure in each injection zone is above the critical pressure that would move injection zone fluids through a hypothetical breach in a confining zone to an adjacent USDW. After Powertech has obtained the site-specific input values for the diffusivity equation, Part IV, Section J of the Class V Area Permit requires Powertech to recalculate critical pressures for each injection zone and adjacent USDW based on site-specific measurements. Similarly, the Class V Area Permit requires Powertech to recalculate the diffusivity equation using site-specific measurements. Powertech may use an input value from scientific literature s as long as the reference and justification for its use is provided. The initial recalculations will use the injection rate needed for disposal of the maximum anticipated volume of treated ISR waste fluids. The Class V Area Permit then directs Powertech to recalculate the diffusivity equation again either increasing or decreasing the injection rate to determine the maximum injection rate for each disposal well. Table 18 shows the nearest potential breeches in the confining zones for each injection zone for each adjacent USDW.

The spreadsheet entitled *EPADiffusivityCalculations.xlsx* shows the EPA calculations of maximum injection flow rate for the DW No. 1 in the Burdock Area and the DW. No. 3 in the Dewey Area. The input values for the calculation were based on information provided in the Class V Permit Application, 12 years of injection activity, 10% porosity in the injection zone and the EPA-calculated critical pressures to move injection zone fluids upward into the Unkpapa/Sundance USDW and downward into the Madison USDW. Based on the critical pressures that would move Minnelusa injection zone fluids into the Unkpapa/Sundance USDW, an injection rate of 170 gpm for DW No. 1 and 234 gpm for DW No. 3 would ensure that the critical pressure is not exceeded within 1,000 feet of the nearest potential breech in the Minnelusa upper confining zone, the Earl Darrow #1 oil and gas test well.

Based on the critical pressures that would move Minnelusa injection zone fluids into the Madison USDW, an injection rate of 110 gpm for DW No. 1 and 97 gpm for DW No. 3 would ensure that the critical pressure is not exceeded within 1,000 ft of the nearest potential breech in the Minnelusa lower confining zone: the Sun #1 Lance Nelson oil and gas test well. Based on these calculations, the maximum injection rate permit limits for each well injecting into the Minnelusa would be the lower calculated values: 110 gpm for DW No. 1 and 97 gpm for DW No. 3.

Final injection rate limits will be set with written Authorization to Commence Injection based on the calculation described under Part II, Section F.3.b in the permit.

Table 18. Nearest Potential Confining Zone Breach for Each Deep Disposal Well

Well Name	Injection Formation	Location	Nearest potential breach through confining zones	Distance from injection well (ft)	Estimated Maximum Injection Rate (gpm)
DW No. 1	Minnelusa	Burdock Area	Earl Darrow #1 oil and gas test well for the Unkpapa/Sundance USDWs Sun #1 Lance Nelson oil and gas test well for the Madison USDW	3,900 17,250	170 110
DW No. 3	Minnelusa	Dewey Area	Dewey Fault for the: Unkpapa/Sundance USDW Madison USDW	9,375	234 97

7.8 Approved Injectate and Injectate Permit Limits

Part IV, Section K of the Class V Area Permit restricts the approved injection fluid to waste fluids from the ISR process. These waste fluids include groundwater produced from well construction, laboratory waste fluids, well field production bleed and concentrated brine generated from the RO treatment of groundwater produced from the well field during groundwater restoration. While most of the groundwater withdrawn from the ISR well field production wells will be reinjected into the well field as part of the ISR and restoration process, there will be a net withdrawal rate, which is referred to as the production or restoration bleed. This bleed will be part of the injectate for the Class V disposal wells.

Due to the types of constituents in the proposed injectate, the Area Permit requires the injectate to be below concentration thresholds for hazardous waste and radioactive waste.

7.8.1 Hazardous Waste Permit Limits

The Area Permit requires the injectate to be below the concentrations for the hazardous waste toxicity characteristic limits found at 40 CFR § 261.24 Table 1. The Table 1 constituents that could be expected in the injectate are the following metals: arsenic, barium, cadmium, chromium, lead, mercury, selenium and silver. The Area Permit requires that the injectate samples be analyzed quarterly for these metals. Arsenic and selenium are present in the uranium ore deposit mineralogy. The hazardous waste permit limits the injectate must meet are listed in Table 19.

USNRC, NUREG-1910, Vol. 1, GEIS, Section 2.7.2 describes typical liquid waste from IS R facilities:
Liquid wastes from ISL facilities are generated during all phases of uranium recovery; construction, operations, aquifer restoration, and decommissioning. Liquid wastes may contain elevated concentrations of radioactive and chemical constituents. Table 2.7-3 shows estimated flow rates and constituents in liquid waste steams for the Highland ISL facility. Liquid waste streams are predominantly production bleed (1 to 3 percent of the process flow rate) and aquifer restoration water. Additional liquid waste steams are generated from well development, flushing of depleted eluant (the fluid that removes uranium minerals from the resin) to limit impurities, resin transfer wash, filter washing, uranium precipitation process wastes (brine), and plant wash down water.

Table 19. Hazardous Waste Concentration Limits for Class V Deep Disposal Wells

Constituent	Total Metals Concentration Limit (mg/L)
Arsenic	5.0
Barium	100.0
Cadmium	1.0
Chromium	5.0
Lead	5.0
Mercury	0.2
Selenium	1.0
Silver	5.0

7.8.2 Radioactive Waste Permit Limits

The Area Permit requires that the injectate be treated to decrease radionuclide activities to levels below the established limits for discharge of radionuclides to the environment, which are listed in 10 CFR Part 20, Appendix B, Table 2, Column 2. These limits are presented in Table 20. Waste streams containing radionuclides below these regulatory limits are not classified as radioactive waste per UIC regulations.

The radioactive constituent limits included in Table 20 are the limits set in Table 16 of the Area Permit that injectate will have to meet. Liquid wastes will be treated to achieve uranium effluent limits in the ion-exchange columns. It is not anticipated that thorium-230 and lead-210 will be present at concentrations above the limits; however, if concentrations are above the limits, the effluent will be treated as necessary to satisfy the Table 16 limits. Radium-226 will be treated in radium settling ponds by adding barium, which will cause the radium to precipitate out of solution.

Table 20. Radioactive Effluent Limits for Class V Deep Disposal Wells.

Radionuclide	Effluent Limits	
	10 CFR 20 App B, Table 2, Column 2 µCi/ml	Permit Limit pCi/l
Lead-210	1.00×10^{-8}	10
Polonium-210	4.00×10^{-8}	40
Radium-226	6.00×10^{-8}	60
Uranium (Natural)	3.00×10^{-7}	300
Thorium-230	1.00×10^{-7}	100

7.9 Tubing-Casing Annulus Pressure

Part III, Section G of the Class V Area Permit requires the annulus between the well casing and injection tubing to be filled with a fluid. Part IV, Section L of the Class V Area permit requires that an induced pressure is maintained on the annulus fluid at all times and that induced pressure must always be at least 100 psi above the injection pressure. If this pressure cannot be maintained, the Area Permit requires Powertech to cease injection and inspect the longstring casing, cement and the injection tubing and test them for mechanical integrity. Part V, Section D.3, Table 17A of the Class V Area Permit includes the requirement that the TCA pressure is continuously monitored.

8.0 MONITORING, RECORDKEEPING AND REPORTING REQUIREMENTS

8.1 Injection Well Monitoring Program

8.1.1 Annual Pressure Falloff Test

Part V, Section A of the Class V Area Permit requires Powertech to conduct an annual pressure falloff test on each Class V injection well to monitor the pressure buildup in the injection zone, including at a minimum, a shutdown of the well for a time sufficient toconduct a valid observation of the pressure falloff curve. A falloff test is a pressure transient test that consists of shutting in an injection well and measuring the pressure falloff. The falloff period is a replay of the injection preceding it; consequently, it is impacted by the magnitude, length, and rate fluctuations of the injection period. Falloff testing analysis provides information about transmissibility[16], skin factor[17], and well flowing and static pressures. Falloff tests provide reservoir pressure data and characterize both the injection interval reservoir and the completion condition of the injection well.

The Area Permit requires Powertech to prepare a plan for running the yearly falloff test using the EPA guideline entitled “UIC Pressure Falloff Testing Guideline” found at https://www.epa.gov/sites/production/files/2015-07/documents/guideline.pdf. Powertech must submit a final test plan to Region 8 for review at least 30 days prior to conducting the initial pressure falloff test and all subsequent annual pressure falloff tests.

The Class V Area Permit requires Powertech to follow the same test procedure for the initial and all subsequent annual tests, so that valid comparisons of reservoir pressure, permeability, and porosity can be made over time. Powertech will analyze test results and submit a report to be prepared by a knowledgeable analyst to the EPA with an appropriate narrative interpretation of the test results. After the first pressure falloff test, the report will include a section comparing the test results with previous year’s test data.

If the well has not injected since the last pressure falloff test was conducted, the Area Permit does not require another pressure falloff test until after the well has started injecting again.

8.1.2 Seismicity

8.1.2.1 Injection-Induced Seismicity

The occurrence of injection-inducted seismicity in the US has been increasing in frequency over the past 6 years. The average number of earthquakes with a magnitude greater than or equal to 3[18] occurring in the central and eastern US has increased from an average of 24 per year from 1973 to 2008 to an average of 193 magnitude greater than or equal to 3 earthquakes from 2009 through 2014, with 688 of these seismic events occurring in

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[16]Transmissibility-The transmissibility of a rock is its capacity to transmit water under pressure. http://www.kgs.ku.edu/General/Geology/Rush/10_ref.html

[17]The effect of well bore damage on the injection flow.

[18] For information on how earthquakes are measured see the USGS website:http://pubs.usgs.gov/gip/earthq1/measure.html

2014. Studies of these seismic events suggest that disposal of large volumes of fluids related to petroleum hydrocarbon production has been the cause of the increasing number of induced seismic events.[19]

Three key components have been identified in areas where induced seismicity has occurred: (1) sufficient injection zone pressure buildup from injection activities, (2) a nearby fault, and (3) a pathway allowing the increased pressure to communicate from the disposal well to the fault. Petroleum engineering methodologies provide practical tools for evaluating the conditions leading to injection-induced seismicity. Petroleum engineering methods typically focus on the potential for reservoir pressure buildup and the reservoir flow pathways present around a well and at a distance, and characterize reservoir behavior during the well's operation.[20]

The presence of a fault in a receiving formation potentially creates more vulnerable conditions for a future seismic event. A fault is a fracture or crack in the rocks that make up the Earth's crust, along which displacement has occurred. During an earthquake, energy is radiated away from the area of the fault in the form of seismic waves. This causes the ground to move as the seismic waves travel away from the fault. Depending on the force of an earthquake, seismic waves can travel far away from the epicenter, and thus be felt far from where the fault is located. The United States Geological Survey (USGS) tracks, records and maps earthquake epicenters and faults in certain areas throughout the Unites States. For area where not much seismic activity has occurred, the USGS may not have much information about seismic events originating or faults located in those areas.[20]

Scientists believe that injection can cause seismicity when the pore pressure (pressure of fluid in the pores of the subsurface rocks) in the formation increases to a level which overcomes the frictional force that keeps a fault stable. Pore pressure incr eases with increases in the volume and rate of injected fluid. Thus, the probability of triggering a significant seismic event during injection where a fault exists in the receiving formation increases with the volume and rate of fluid injected. In addition, the larger the volume injected over time, the more likely a fault could be intersected, because the fluid will travel farther within a formation. When injected fluid reaches a fault, frictional forces that have been maintained within that fault can be reduced by the fluid. At high enough pore pressure, the reduction in frictional forces can cause the formation to shift along the fault line, resulting in a seismic event. Therefore, limiting the rate and volume of fluids injected limits the potential for seismicity. [20]

Because increases in pore pressure due to the rate and the volume of injected fluid can act on existing faults and provide a mechanism for induced seismicity, most examples of injection-induced seismicity are in cases where the receiving formation has low permeability and/or the pressure or volume of fluid injected over time is quite large. Formations such as crystalline basement rock (deeper geological formations of igneous or metamorphic rock that underlie layers of sedimentary rock), have very low permeability. Permeability is the ease with which a fluid can flow through the pores in a rock layer. For example, in the case of the Northstar 1 injection well in Youngstown, Ohio, injection occurred into very low permeability, crystalline bedrock. [20]

Where permeability is low, injected fluids cannot flow easily through the pores in this rock and therefore flow is oriented mainly through existing fractures or faults in the rock. These kinds of rock formations have high

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[19] Rubinstein and Mahani, 2015, Myths and Facts on Wastewater Injection, Hydraulic Fracturing, Enhanced Oil Recovery, and Induced Seismicity.

[20] EPA Underground Injection Control National Technical Workgroup, 2015, Minimizing and Managing Potential Impacts of Injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches.

transmissivity and low storativity. This means that the formation cannot store a lot of fluid; rather fluid moves father and faster in these formation than in more porous formations. Because of the high transmissivity and low storativity of these kinds of rocks, the potential exists to induce pore pressure increases at considerable distances away from the injection well. Injection into a more permeable sedimentary formation is much less likely to induce seismicity. [20]

To minimize conduits for fluid to potentially contaminate USDWs, operating conditions in an injection well permit can expressly limit the injection pressure to prevent fracturing (or cracking of the rock) of the injection zone. Limiting injection pressure provides the secondary benefit of preventing fractures that could also act as conduits through which fluids could flow and act upon an existing fault. In order to induce seismicity, pressure from the fluid injection would have to: 1) be great enough to create or reopen fractures that would act as a conduit for the fluid to reach the fault; and 2) exert enough pressure and flow to overcome the frictional forces in, and thereby destabilize, the fault. [20] After well construction has been completed and Powertech provides the information required to obtain the Limited Authorization to Inject for the EPA, the Step Rate Test discussed in Section 5.3.4.2 will provide data on the amount of pressure necessary to fracture the injection zone.

In addition to concerns about injection-induced seismicity, there have been questions raised as to the relevance of natural seismicity to injection well permitting. When reviewing permit applications, the EPA reviews available USGS information on seismic activity at the location of the well. As described, above, knowledge of seismic events that originated in the vicinity of the proposed well can be informative about whether faults exist in that location. However, although earthquakes can be felt miles from their epicenter, earthquakes are not indicative of faults in all the areas where they are registered. Thus earthquakes originating away from the proposed well location do not provide information about faults at the location for the proposed well. [20]

Of the hundreds of thousands of injection wells operating in the United States, the EPA is not aware of any case where a seismic event, whether naturally occurring or induced, caused an injection well to contaminate a USDW. The EPA is also unaware of any studies that have been done specifically to determine whether injection wells have caused contamination of a USDW during a seismic event. There have not been any reports of earthquakes affecting wells in the cases of induced-seismicity in Ohio, Texas, West Virginia or Colorado. [20]

A number of factors help to prevent injection wells from failing as a result of a seismic event and contributing to the contamination of a USDW. Most deep injection wells, those that are classified as Class I or Class II injection wells, are constructed to withstand significant amounts of pressure. They are typically constructed with multiple steel strings of casings that are cemented in place. Deep injection wells are typically designed, using casing and cement standards developed by the American Petroleum Institute (API) and oil field service companies, like Halliburton Services, to withstand significant internal and external pressure. See the Halliburton Redbook at http://www.halliburton.com for the industry standards in casing and cementing wells. Furthermore, injection well permits require mechanical testing to ensure integrity before wells are operated and many are continuously monitored after testing to ensure that mechanical integrity is maintained. Injection wells can be designed to automatically shut in and cease operating if a seismic event occurs that affects the operation and mechanical integrity of the well.[20]

Weingarten et al., 2015[21], determined "that injection rate is the most important well operational parameter affecting the likelihood of an induced seismic event in regions and basins potentially prone to induced seismicity."

Table 21 compares injection rates for injection wells in Arkansas [22] located near an area with induced seismicity, injection wells in Texas[23] associated with induced seismicity, the US Bureau of Reclamation Paradox Valley injection well in western Colorado, the Rocky Mountain Arsenal wells near Denver, Colorado and the estimated maximum injection rate calculated for the DW No. 1 Class V injection well (110 gpm) in Section 4.4.2.2 converted to cubic meters per month. The Dewey-Burdock well injection rate is lower than the other wells in Table 21. Wells AR SWD 5 and 6 have the second and third lowest injection rates. Looking more closely at AS SWD 6, this well injected into a relatively shallow injection zone (2,224 to 2,316 feet) and was not directly associated with any seismic events. The injection zone depth for well AR SWD 5 was 7,805 to 10,971 feet and located near a Precambrian basement fault in hydrologic communication with the injection zone. The injection zone for well AR SWD 5 was a low porosity dolomite with high permeability from fractures and faults, so the injectate moved into the fractures and fault zone rather than pore space. The peak injection pressure for well AR SWD 5 was 2,843 psi. As discussed above, these conditions fit the scenario for injection-induced seismicity.

Table 21. Comparison of Injection Rates for the Arkansas Disposal Wells and Other Wells causing Induced Seismicity with the Estimated Maximum Injection Rate for the Dewey -Burdock Class V Deep Injection Wells.

Injection Well Name	Volume of Injected Fluids (m^3/month)
AR SWD 1	62,662
AR SWD 2	54,058
AR SWD 3	23,435
AR SWD 4	29,573
AR SWD 5	19,580
AR SWD 6	18,629
AR SWD 7	37,997
AR SWD 8	41,280
Rocky Mountain Arsenal Wells	37,857
USBR Paradox Valley Well	53,148
TX Injection Wells Frohlich,	24,000
Dewey-Burdock Class V Wells	18,288

In contrast, the Dewey-Burdock deep Class V Upper Minnelusa injection zone is of higher porosity and is located approximately 990 vertical feet above the Precambrian basement at the Dewey-Burdock Project Site. As shown in Table 17, the estimated injection pressure for the Class V wells is 351 psig at the Burdock well and 423 psig at the Dewey well. The EPA does not expect that the Dewey-Burdock deep Class V injection wells will cause injection-induced seismicity. If injection-induced seismicity should occur, it will be detected by the monitoring requirements discussed in Section 8.1.2.2.

[21] Weingarten et al., 2015, High-rate injection is associated with the increase in U.S. mid-continent seismicity.

[22] Horton, 2012, Disposal of Hydrofracking Waste Fluid by Injection into Subsurface Aquifers Triggers Earthquake Swarm in Central Arkansas with Potential for Damaging Earthquake.

[23] Frohlich, 2012, Two-year survey comparing earthquake activity and injection-well locations in the Barnett Shale, Texas.

8.1.2.2 Seismic Monitoring Requirements

The U.S. Geological Survey (USGS) Earthquake Hazards Program operates an email notification service which reports real-time earthquake events for any area specified by the user. The Area Permit requires Powertech to subscribe to this service, known as the Earthquake Notification Service (ENS). Details for the ENS can be found at:
https://sslearthquake.usgs.gov/ens/
and a subscription can be initiated at:
https://sslearthquake.usgs.gov/ens/register

Part V, Section B.2 of the Class V Area Permit requires Powertech to immediately cease injection if any seismic event is reported within two miles of the permit boundary, and report to EPA within twenty-four (24) hours. Injection will not resume until the Powertech has obtained approval to recommence injection from EPA. For any seismic event occurring between two and fifty miles of the Area Permit Boundary, that event will be recorded and reported to EPA on a quarterly basis.

8.1.3 Ongoing Demonstration of Mechanical Integrity

The UIC regulations state that an injection well has mechanical integrity if:

1. There is no significant leak in the casing, tubing, or packer (internal mechanical integrity); and
2. There is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore (external mechanical integrity).

The Area Permit prohibits injection into a well which lacks mechanical integrity.

Part II, Section H of theClass V Area Permit requires an initial mechanical integrity d emonstration for each injection well prior to injection. Part III, Section L of the Class V Area Permit requires a mechanical integrity demonstration following any workover which affects the tubing, packer or casing. Part V, Section C of the Class V Area Permit requires ongoing mechanical integrity demonstration at least once every five (5) years after the last successful demonstration of internal mechanical integrity. If the well has not been used for injection activity for 24 consecutive months, a demonstration of mechanical integrity is required every two years. A demonstration of mechanical integrity includes both internal and external testing. As required under Class V Area Permit Part V, Section C.6.b, monitoring the TCA pressure is the method that will be used to demonstrate internal mechanical integrity of the well injection tubing, packer and casing. The Area Permit requires that the TCA pressure be maintained a minimum of 100 psi above the injection pressure at all times. Because this Class V Area Permit includes many of the protective measures contained in Class I regulations, continuous monitoring of the TCA is required as a permit condition. A rapid, unexplained change in the TCA pressure could signal a leak in the injection tubing, the packer or the well casing. Continuous monitoring of TCA pressure will allow early detection of a possible breach of internal mechanical integrity so it can be addressed before injectate leaks from the well into another formation besides the injection zone. The procedure for demonstrating internal mechanical integrity is the TCA pressure test and is included in Part V, Section C.6.b of the Area Permit.

The external mechanical integrity testing required under Part V, Section C.6.c demonstrates that there is no significant fluid movement through the cement filling the space between the outermost well casing and the drillhole wall. The Area Permit requires that initial external mechanical integrity be demonstrated by a Cement Bond Log and the well construction cementing record. After the initial demonstration, ongoing external mechanical integrity testing can be demonstrated by a Radioactive Tracer Survey which detects any movement of a radioactive substance outside of the injection zone and a Temperature Survey test which detects any temperature anomaly outside the injection zone.

8.1.4 Monitoring of Well Operating Parameters

Part V, Section D.3, Table 17of the Class V Area Permit lists all the monitoring requirements along with recoding and reporting requirements for each Class V deep injection well. These include continuous monitoring of injection pressure, injection flow rate, cumulative fluid volume, TCA pressures and the differential pressure between the injection pressure and the TCA pressure. These parameter values must be recorded daily. A recording, at least once every thirty (30) days, must be made of themonthly average injection pressure, maximum injection pressure for the month, annulus pressure, monthly injection flow rate and cumulative fluid volume injected. This information is required to be reported quarterly as part of the Quarterly Monitoring Report to the EPA. A summary of injection pressure, rate and volume monitoring requirements are presented on Table 22.

The Area Permit also requires monitoring of injectate chemistry and physical properties. The Area Permit requires Powertech to collect samples of the injected fluid quarterly and analyze them for the constituents listed in Tables 19 and 20 (of this document). The injectate samples shall be collected in a manner that allows them to be analyzed using the methods shown in Table 16 of the Area Permit or other equivalent methods approved by the EPA in advance. The analytical results shall be reported to the EPA quarterly as part of the Quarterly Monitoring Report to the EPA. Any time a new waste stream source is added or removed from the injectate, a new injectate sample shall be collected and analyzed.

Thorium-230 and lead-210 are decay products of uranium; however, they are not expected to occur in the fluid waste stream. Initial monitoring of the injectate will include analysis for thorium-230 and lead-210, but if they are not detected in the waste stream after the first analysis, subsequent monitoring will not require analysis for thorium-230 and lead-210. If the waste stream changes, for example once aquifer restoration begins, a new waste stream from the plant is added to the injectate or groundwater from a new well field is added to the waste stream, then analysis will be required for the full suite of analytes. After a change in the waste stream and if thorium-230 and lead-210 are not detected in the waste stream after the first analysis, subsequent monitoring will not require analysis for thorium-230 and lead-210.

If formation testing does not confirm that the TDS concentration of an injection zone is greater than 10,000 mg/L TDS, then the injection zone is a USDW. The analytical requirements and permit limits would be different for injection into a USDW. Under this permit as currently drafted, injection into a USDW is prohibited. If Powertech chooses to pursue the use of an injection zone that is a USDW, the EPA will require a permit modification. A major permit modification involves issuing a draft permit modification and a public participation process seeking comments on only the proposed modifications.

Table 22. Summary of Monitoring and Reporting Requirements.

Parameter	Monitoring Frequency	Recording Frequency	Reporting Frequency
Injection Flow Rate	Continuous	Daily	
Average Flow Injection Rate	Monthly	Monthly	Quarterly
Maximum Injection Flow Rate	Monthly	Monthly	Quarterly
Minimum Injection Flow Rate	Monthly	Monthly	Quarterly
Injection Pressure	Continuous	Daily	
Average Injection Pressure	Monthly	Monthly	Quarterly
Maximum Injection Pressure	Monthly	Monthly	Quarterly
Minimum Injection Pressure	Monthly	Monthly	Quarterly
Cumulative Injectate Volume	Continuous	Monthly	Quarterly
Average Injectate Volume	Monthly	Monthly	Quarterly
Maximum Injectate Volume	Monthly	Monthly	Quarterly
Minimum Injectate Volume	Monthly	Monthly	Quarterly
TCA Pressure	Continuous	Daily	
Average TCA Pressure	Monthly	Monthly	Quarterly
Maximum TCA Pressure	Monthly	Monthly	Quarterly
Minimum TCA Pressure	Monthly	Monthly	Quarterly
Differential Pressure between injection pressure and TCA pressure	Continuous	Daily	
Average Differential Pressure	Monthly	Monthly	Quarterly
Maximum Differential Pressure	Monthly	Monthly	Quarterly
Minimum Differential Pressure	Monthly	Monthly	Quarterly
TCA Fluid Level (for injecting wells)	Weekly	Weekly	Quarterly
TCA Fluid Level (for wells not injecting)	Monthly	Monthly	Quarterly
TCA Fluid Level (for wells not injecting but 10% decrease in TCA pressure occurs within a month)	Twice a Month	Twice a Month	Quarterly
TCA Fluid Addition or Removal	As needed	When it occurs	Quarterly
Injectate sampling and analysis	Quarterly	Quarterly	Quarterly
Injectate Specific Gravity	Weekly	Weekly	Quarterly

8.1.5 Protective Automated Monitoring and Remote Monitoring

As described in Section 6.5, the Area permit requires an automated control system with control switches to alarm the operator in the event that any of the Area Permit condition related minimum or maximum set points are met, and automatically halts injection operations until the problem is identified and corrected. For example, a high injection pressure switch (set at or just below the Area Permit MAIP) and a low annulus differential pressure switch (set just above the Area Permit minimum) will shut off injection pump power and will alarm the operator so that the well can be fully isolated and secured. The Area Permit requires that these systems operate continuously except in the event of power failure which will shut down injection operations. Any alarms, automatic shutdowns dues to permit limits and power failures shall be recorded in a narrative, along with causes and actions taken to correct the situation, and included in the next Quarterly Report.

If the Class V Disposal Wells are monitored and operated remotely, the Area Permit includes the following special conditions will be applicable to each well. For the purpose of this Area Permit, remote monitoring is defined as injection into the wells when a trained operator is not present at the well site or in monitoring control room and able to receive information from shut-down alarms and able to physically respond to the well controls or the wellhead within 15 minutes of a compliance alarm.

In order for the proposed Dewey-Burdock deep disposal wells to be monitored and operated remotely, the following special conditions must apply to each well:

1. *Local operating system and remote monitoring system:* If remote monitoring is to be used to operate the well, an automatic paging system stall be installed that is designed to alert designated on-call, off-site personnel in the event of a well alarm or shut-in. The paging system will be equipped with a back-up power supply.
2. *Response to automatic shut-downs:* Alarm shut-downs of the operating well related to Area Permit compliance limits established for well operation will be investigated on-site by a trained operator within three (3) hours of pager notification of the occurrence.
3. *Loss of power to the control system:* In the event of a power failure beyond the capability of the back-up power supply shuts down the control system, the well shall be automatically shut-in.
4. *Loss of dial tone:* If the automatic pager cannot get a dial tone for 90 minutes, the well shall automatically be shut-in.
5. *Restart of the well after an automatic shut-in:* Restart of the well after a shut-in related to an Area Permit condition alarm (including, but not limited to, injection pressure, annulus differential pressure, loss of dial tone for more than 90 minutes or control system power failure) shall require the physical presence of the operator on-site to verify compliance before the well can be restarted.
6. *Restart of the well after shut downs unrelated to a Permit condition:* If the well is shut-in for more than 48 hours for circumstances unrelated to Permit conditions, restart of the well shall require the physical presence of the operator on-site.
7. *Monthly operator inspections:* If fluid injection occurs during the period of any month and the well is being monitored remotely, a trained operator shall physically visit the site to inspect the facility at a minimum frequency of not less than once per month. This inspection shall verify the correct operation of the remote monitoring system by review of items such as, but not limited to, a comparison of the values shown on mechanical gauges with those reported by the remote operating system.
8. *Weekly operator inspections:* Unless annulus pressure changes by more than 10 percent per week while the well is injecting, only one annulus fluid level per week shall be required to be observed, recorded and reported when injection takes place.
9. *Annulus tank fluid level measurements:* When the well is not actively being used for injection, one annulus tank fluid level measurement shall be taken, recorded and reported per month unless annulus fluid pressure decreases more than 10 percent per month. In such cases of increased annulus pressure change, annulus fluid level measurements shall be taken, recorded and reported twice per month.
10. When not in use by a trained well operator, offloading connections shall be secured and shall be locked at the valves leading to waste water tanks so that access is restricted to trained well operators.
11. In the event of well shut-down, it may become necessary to transport fluid by truck to an alternate well site within the proposed Class V Area Project Area. Offloading of fluid from transports can only occur with a trained operator physically present on site. A waste related log sheet and/or waste manifest file will be maintained documenting that a trained well operator allowed fluid to be unloaded. At a minimum, waste log entries are to include operator name, date, time, truck identification and approximate volume.

8.2 Records Retention

1. Records of calibration and maintenance, and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit shall be retained for a period of AT LEAST THREE (3) YEARS from the date of the sample, measurement, report, or application. This period may be extended any time prior to its expiration by request of the EPA.
2. Records of the nature and composition of all injected fluids must be retained until three (3) years after the completion of any plugging and abandonment (P&A) procedures specified under 40 CFR § 144.52(a)(6) or under Part 146 Subpart G, as appropriate. The EPA may require Powertech to deliver the records to the EPA at the conclusion of the retention period. Powertech shall continue to retain the records after the three (3) year retention period unless Powertech delivers the records to the EPA or

obtains written approval from the EPA to discard the records.

3. Powertech shall notify the EPA as to the location where injection well records are maintained. Powertech shall notify the EPA if this location changes.

8.3 Quarterly Reports

Following authorization to begin injection, Powertech shall submit Quarterly Reports to the EPA summarizing the results of the monitoring required above whether the well is operating or not. Reporting periods and due dates for Quarterly Reports are shown in Table 23. EPA Form 7520-8 *Injection Well Monitoring Report* (found at http://water.epa.gov/type/groundwater/uic/reportingforms.cfm) may be used to submit the Quarterly Reports, however, the monitoring requirements specified in this Permit are mandatory even if EPA Form 7520-11 indicates otherwise.

Table 23. Quarterly Report Due Dates

REPORTING QUARTER	REPORTING PERIOD	REPORT DUE TO EPA
1st Quarter	January 1 – March 31	May 15
2nd Quarter	April 1 – June 30	August 15
3rd Quarter	July 1 – September 30	November 15
4th Quarter	October 1- December 31	February 15

9.0 PLUGGING AND ABANDONMENT REQUIREMENTS

9.1 Plugging and Abandonment Plan

Prior to abandonment, the well shall be plugged in a manner thatisolates the injection zone and prevents movement of fluid into or between USDWs, and in accordance with any applicable FederaState or local law or regulation. The plugging and abandonment plan is described in Part VI of the Area Permit. The Area Permit requires the following steps prior to abandonment of the wells:

1) Tubing, packer and other downhole apparatus shall be removed.
2) A temperature survey is required to confirm external mechanical integrity if it has been more than two years since the last test was run. If any pathways are discovered in the external casing cement, then remedial cementing will be required.
3) A pressure falloff test will be required if it has been more than 6 months since the last test.
4) Each well shall be filled with cement from total depth (or in the case of DW No. 1, PBTD) to surface in two to three stages.
5) Within sixty (60) days after plugging the owner or operator shall submit Plugging Record (EPA Form 7520 13) to the EPA.
6) The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation.

9.2 Inactive Wells

UIC regulations found at 40 CFR § 144.52(a)(6) requires:

After a cessation of operations of two years the owner or operator shall plug and abandon the well in accordance with the plan unless he:

(i) Provides notice to the EPA;
(ii) Describes actions or procedures, satisfactory to the EPA, that the owner or operator will take to ensure that the well will not endanger USDWs during the period of temporary abandonment. These actions and

procedures shall include compliance with the technical requirements applicable to active injection wells unless waived by the EPA.

However, because of the post-restoration monitoring requirements for wellfields in the Class III permit, there may be a period of more than two years during which there will be no injection activity. However, the EPA does not want Powertech to close all of the Class V injection wells in case additional restoration activity is required under the Class III permit that would result in the production of waste fluids that would need to be disposed of in the Class V injection wells. Therefore, the Area Permit requires Powertech to fulfill the other requirements of 40 CFR § 144.52(a)(6) to ensure that the inactive well will not endanger USDWs during the period of temporary abandonment. The Area Permit requires Powertech to notify the EPA at the end of 24 months of no injection activity and conduct a demonstration of internal and external mechanical integrity before the end of 24 months. As long as the well remains inactive, demonstration of internal and external mechanical integrity is due every 24 months as indicated in Table 17H of the Area Permit.

10.0 FINANCIAL RESPONSIBILITY

10.1 Demonstration of Financial Responsibility Requirements

Powertech is required to maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the EPA. Powertech shall show evidence of such financial responsibility to the EPA by the submission of a surety bond, or other adequate assurance such as financial statements or other materials acceptable to the EPA. The EPA may, on a periodic basis, require the holder of a permit to submit a revised estimate of the resources needed to plug and abandon the well to reflect inflation of such costs, and a revised demonstration of financial responsibility if necessary. Initially, the Powertech has proposed to demonstrate financial responsibility with an irrevocable letter of credit with a standby trust agreement, as indicated in the June 2011 RAI Response TR RAI MI-4(a) submitted to the NRC. Powertech must set up a separate agreement with the EPA perrequirements under Part VIII of the Class V Draft Area Permit.

Depending on the type of financial instrumentused to demonstrate financial responsibility, evidence of continuing financial responsibility may be required to be submitted to the EPA annually.

Powertech based the estimated for the costs on plugging and abandoning all four injection wells using the volume of cement required for DW No. 1, which has larger diameter long string casing than the other three wells. The estimated costs and list of anticipated activities for plugging and abandonment of all four wells are included in Appendix B of this document.

10.2 Updated Estimate of Costs for Well Plugging and Abandonment

Because the information included in Appendix B was estimated in 2010, the Area Permit requires Powertech to submit an updated cost estimate within 21 days after the Final Area Permit becomes effective.

10.3 Timing for Demonstration of Financial Responsibility

The Area Permit requires Powertech to have the financial instrument in place and EPA approval of Financial Responsibility before Class V injection well construction can begin. The Area Permit prohibits well construction before financial responsibility is in place. If additional wells are requested under the Area Permit, the cost of plugging and abandonment of the additional wells will be added to the demonstration of financial responsibility based on an updated cost estimate to reflect the most recent cost of labor and supplies required.

11.0 Considerations under Federal Law

As part of the permit process, pursuant to 40 CFR §144.4, EPA is required to consider whether other federal laws, specifically Section 106 of the National Historic Preservation Act and Section 7 of the Endangered Species Act, apply to the issuance of a UIC permit. EPA determined that these laws are applicable and followed the requirements and procedures of each as described below.

11.1 The National Historic Preservation Act

The document entitled *The Environmental Protection Agency National Historic Preservation Act Compliance and Review for the Proposed Dewey-Burdock In-Situ Uranium Recovery Project*, which is part of the Administrative Record for the UIC Draft Area Permits, discusses how the EPA intends to comply with Section 106 of the National Historic Preservation Act.

11.2 The Endangered Species Act

Section 7(a)(2) of the Endangered Species Act (ESA), 16 U.S.C. § 1536 (a)(2), requires federal agencies to ensure that actions they authorize, fund, or carry out are not likely to jeopardize the continued existence of federally-listed endangered or threatened species or result in the destruction or adverse modification of designated critical habitat of such species. The EPA has determined that a decision to issue a Class V area permit for authorization of injection well operations at the proposed Dewey-Burdock uranium in-situ recovery site would constitute an action that is subject to the Endangered Species Act and its implementing regulations (50 CFR part 402). Accordingly, the EPA will comply with these regulations by determining what, if any, effects this action will have on any federally-listed endangered or threatened species or their designated critical habitat and by following any required ESA procedures. The EPA's determination will be documented as part of the Administrative Record supporting the final Class V area permit decision.

12.0 References

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Appendix A

Stratigraphic Log of the Minnelusa Formation from the Earl Darrow #1Oil and Gas Exploration Well

1616	TOP MINNELUSA
1620 - 1660	Sand, medium grained, rounded to sub-rounded, vitreous to frosted, friable, white to pink to red, good porosity in part, clay-filled in part, fairly well sorted. Red sand is dolomitic. Sand becomes more red at the base. No show.
1660 - 1680	Anhydrite, gray, hard, dense.
1680 - 1690	Sand, medium grained, rounded to sub-rounded. vitreous to frosted, friable, slightly dolomitic. red. Traces of good porosity. No show.
1690 - 1750	Anhydrite, gray, hard, dense. Traces of red and gray silty shale. Traces of dolomite and sand.
1750 - 1775	Shale, red to gray, silty. Traces of sand. Traces of medium grained, well sorted, friable, clay-filled red to pink sand. No show.
1775 - 1830	Dolomite, buff to gray, fairly hard, sucrosic.
1830 - 1855	Dolomite - anhydrite, buff to gray, micro-crystalline, very hard.
1855 - 1865	Sand, medium to coarse grained, rounded to sub-rounded, vitreous to frosted, friable, poorly sorted,white, clay-filled, dolomitic, poor porosity. No show.
1865 - 1880	Dolomite, buff to gray, traces of pink.
1880 - 1905	Dolomite, buff to white, dense. Traces of sand and anhydrite.
1905 - 1915	Sand, medium grained, dolomitic and anhydritic. No show.
1915 - 1940	Anhydrite, white to buff to pink. Some gray.
1940 - 1960	Dolomite, buff to pink to red, mostly pink, hard, dense. 20% buff to red very dolomitic sand, very hard.
1960 - 2000	Dolomite, as above with increase in fairly friable sand as above. No show.
2000 - 2020	Anhydrite, white to buff to gray.
2020 - 2030	Dolomite, buff to gray to pink.

SAMPLE DESCRIPTION (continued)

2030	TOP RED SHALE MARKER
2030 - 2042	Shale, red to pink to yellow, fissile, metallic luster.
2042 - 2070	Dolomite, white to buff to gray to pink, hard and dense.
2070 - 2085	Dolomite, gray, very hard, micro-crystalline. Shale, very black, hard, brittle.
2085 - 2125	Dolomite, dark gray to black, some brown and tan, micro-crystalline. Chert, vitreous, angular, some smoky. Dark gray to black dolomitic shale with oily taste. No cut or fluorescence.

Five foot samples from 2100 to 2250 feet.

2125 - 2145	Dolomite, as above, with no chert. Traces of a poorly sorted dolomitic sand. No show.
2145 - 2151	Dolomite, medium to dark gray, micro-crystalline, hard, slightly anhydritic.

Core #1 2155 to 2206 feet is adjusted up four feet in depth to fit the electric log.

2151 - 2152.5	Sand, gray, fine grained, well sorted, anhydrite filled, hard, tight, no porosity. No show.
2152.5 - 2153	Sand, gray, fine grained, well sorted, trace of porosity, slightly dolomitic, No show.
2153 - 2158	Dolomite, gray, hard, dense, micro-crystalline. Slightly shaley.
2158 - 2160.5	Shale, black, carbonaceous, micaceous, hard.
2160.5 - 2167	Sand, gray to greenish gray, fine grained, anhydrite and dolomite filled, well sorted, hard, tite, no porosity. No show.
2167 - 2171	Anhydrite, gray, hard.
2171 - 2176	Shale, black, micaceous, carbonaceous, with occasional anhydrite streaks.
2176 - 2180	Shale, black, carbonaceous, micaceous, with sulfur odor.
2180 - 2188.5	Sand, gray to greenish gray, fine grained, anhydrite and dolomite filled, well sorted, hadr, tight, no porosity. No show.
2188.5-2189.5	Shale, gray, hard.

SAMPLE DESCRIPTION (continued)

2189.5 - 2194	Sand, gray to greenish gray, fine grained, anhydrite and dolomite filled, well sorted, hard, tight, no show.
2194 - 2202	Dolomite, gray to brown, anhydritic, trace of vuggy porosity.

End of core #1

2202 - 2206	Shale, black, carbonaceous, micaceous.
2203 - 2218	Dolomite, gray, dense.
2218 - 2220	Shale, black, micaceous, carbonaceous.
2220 - 2228	Dolomite, gray, dense.
2228 - 2230	Shale, black, carbonaceous, micaceous.
2230 - 2238	Dolomite, gray, dense.
2238 - 2242	Shale, black, carbonaceous, micaceous.
2242 - 2250	Sand, fine to medium grained, rounded, vitreous to frosted, hard to friable, anhydrite filled and dolomite filled, tight. No show.

Ten foot samples from 2250 to 2450 feet. Total depth.

2250 - 2268	Dolomite, gray, hard.
2268 - 2272	Black silty shale with oily taste.
2272 - 2298	Dolomite, gray, hard, traces of sand and anhydrite as above.
2298 - 2300	Black silty shale.
2300 - 2325	Dolomite, gray to dark gray, hard, dense, traces of sand as above.
2325 - 2395	Sand, fine grained, rounded, frosted, very calcareous, lime or dolomite matrix. Very dense, tight, buff to tan. No show. Traces of medium grained, rounded, frosted, friable, slightly clay-filled sandstone. Trace of porosity, white. No show.
2395 - 2400	Dolomite, gray, dense.
2400 - 2450	Sand, fine to medium grained, mostly fine, rounded, frosted, calcareous, friable. Trace to fair porosity, white to buff to gray. No show.
2450	Total Depth.

Appendix B

Estimated Plugging Cost for Dewey-Burdock Disposal Wells

FIELD OPERATIONS	Unit Cost	Units Req'd.	Total Cost
Subcontractors - Direct bill to Powetech			
Mob/demob & Location Preparation	$6,000	1	$6,000
Workover Rig and Associated Equipment (days)	$5,000	4	$20,000
Rental Tools (days)	$2,500	4	$10,000
Rental Tubing Inspection	$6,000	1	$6,000
Falloff Test	$6,500	1	$6,500
RAT Log	$4,500	1	$4,500
Trucking	$4,000	1	$4,000
Contract Labor	$2,000	2	$4,000
Cement (384 sx), pumping & equipment	$9,600	1	$9,600
Contingency	$8,000	1	$8,000
Total Estimated Subcontractor Charges			$78,600
Test Design and Project Management (hours)	$115	24	$2,760
Supervision (days)	$850	5	$4,250
Travel (hours)	$115	8	$920
Field Truck and Fuel (days)	$150	6	$900
Per Diem (days)	$100	6	$600
Data Analysis (lump sum)	$2,000	1	$2,000
Report Preparation (hours)	$115	24	$2,760
Total Estimated Petrotek Charges			$14,190
TOTAL ESTIMATED COST PER WELL			**$92,790**
TOTAL ESTIMATED COST FOR FOUR WELLS			**$371,160**

Assumptions:

P&A costs are for well with largest casing capacity (DW No. 1); other P&A costs would be lower
Subcontractors will bill Powertech directly - otherwise a 12.5% markup will apply.
Field activities can be completed in 5 days; otherwise T&M rates will apply.
Falloff test is required if > 6 months since last test; RAT log required if > 2 years since last log.
The well is cemented from bottom to top in 2 - 3 stages.
Powertech will be responsible for disposal of all well equipment.